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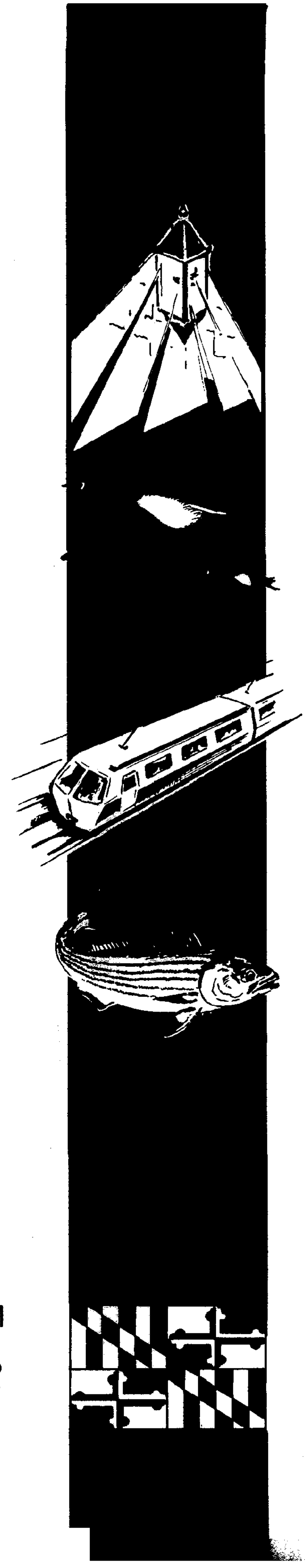

POWER PLANT CUMULATIVE ENVIRONMENTAL IMPACT REPORT

NOVEMBER 1978

Dept of Natural Resources

MARYLAND POWER PLANT SITING PROGRAM

ENT OF NATURAL RESOURCES ■ DEPARTMENT OF HEALTH AND HYGIENE ■ DEPARTMENT OF ECONOMIC AND COMMUNITY DEVELOP- DEPARTMENT OF STATE PLANNING ■ COMPTROLLER OF THE TREASURY SERVICE COMMISSION

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STATE OF MARYLAND
DEPARTMENT OF NATURAL RESOURCES
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ANNAPOLIS 21401
269-3041

January 18, 1979

The Honorable Harry Hughes
Executive Department
Office of the Governor
State House
Annapolis, Maryland 21404

Dear Governor Hughes:

The second Cumulative Environmental Impact Report prepared pursuant to the Maryland Power Plant Siting Act is forwarded. The Report colligates the results of the studies of the Power Plant Siting Program with respect to the cumulative impact of power plants on Maryland's environment.

Major findings presented in the Report are as follows:

Existing and proposed power plants will provide adequate electricity to Maryland over the next ten years. The entire state is in compliance with the air quality standards for two of the three pollutants emitted in significant quantities by power plants, sulfur oxides and nitrogen oxides. For the third pollutant, particulates, air quality in the general areas of Baltimore City and the Potomac River Valley near Bloomington is in violation of Federal ambient air quality standards. Studies to date have revealed no significant cumulative aquatic impacts due to power plant operation. Radioactive discharges from the Calvert Cliffs plant have remained less than 10% of the permitted limitations on emissions.

Experience indicates the importance of the continued collection and analysis of environmental data, both for comprehensive site-specific field investigations of individual power plants and for cumulative assessments of all power plants operating in the State. Several specific recommendations relating to environmental policy are listed in the Report.

In some respects the Federal government is more of a hindrance than a help to the State in its effort to achieve the purpose of the Power Plant Siting Act. Actions of the various federal agencies and officials are unpredictable which leads to an undependable basis for long range Federal-State coordination.

For instance, a continual stream of new federal laws creates additional requirements that cause plans to be outmoded as fast as they can be developed. Policy direction governing the use of fuels is in a continual state of flux and often a policy such as that to encourage the production of coal for utilization in power plants is immediately neutralized by another set of changes such as those contained in the Clean Air Act Amendments of 1977. Another example is the vacillation of the Federal government with respect to various schemes for resolution of the nuclear waste disposal issue.

The current unpredictable and undependable behavior of the Federal government points up the importance of a strong state capability to protect the environment while providing for an adequate supply of electric energy as provided for in the Power Plant Siting Act.

Sincerely yours,

James B. Coulter

James B. Coulter
Secretary

JBC:PM:pc
Enclosure

PPSP-CEIR-2

POWER PLANT
CUMULATIVE ENVIRONMENTAL
IMPACT REPORT

NOVEMBER 1978

Maryland Department of Natural Resources

Comments and requests for additional copies should be addressed to Editor, Cumulative Environmental Impact Report, Power Plant Siting Program, Maryland Department of Natural Resources, Tawes State Office Building, Annapolis, Maryland 21401

FOREWORD

The job of compiling and editing the Cumulative Impact Report could not have been accomplished without the help and cooperation and many people and organizations.

Editorial content of the individual chapters was aided by members of the PPSP staff. I thank Dr. Steven Long for his contributions to Chapters IV and VI and Mr. Howard Mueller for his contributions to Chapters I and V.

Special thanks go to Mr. Jorgen Jensen, Ms. Nadine Johansen and Ms. Lois Craig of Martin Marietta Corporation for their perseverance in reviewing and typing the many drafts of this document.

I would also like to acknowledge the cooperation and aid of the following individuals and organizations:

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Randy A. Roig
Editor

SUMMARY

Chapter I - Energy

During the five years prior to 1973, Maryland electric energy peak demand grew by an annual average rate of 8.3%, and consumption grew by 8.6%. During the 1973-1975 period, those rates dropped to 0.0% and -0.3%, respectively. In the 1975-1977 period, growth in both peak demand and consumption resumed, to 5.0% and 7.4%/year. Forecasts prepared by the Power Plant Siting Program and the Maryland utilities project growth in peak demand over the next ten years to average 4.0%/year for the utility systems serving Maryland (3.4%/year for the portion of their service territories within Maryland).

The total time required for the construction of large-scale electric generating plants ranges up to 8-10 years for coal plants and up to 15 years for nuclear plants. Utilities plan for new capacity requirements ten or more years in advance. Maryland utility systems plan to add 3,024 megawatts of generating capacity by 1987 within Maryland. An additional 4,245 megawatts of capacity within Maryland is tentatively projected for the period 1987 to 1997. The projected increase in load factors will result in the addition of relatively more baseload capacity by these systems.

Comparison of capacity from existing and proposed plants with demand projections for the utility systems serving Maryland indicate that adequate electric power will be available over the next ten years. Based on Power Plant Siting Program demand projections and completion of planned generation additions, utility capacity plans will result in reserve margins above 25% for most of the period, with reserve margins reaching 30% by 1980, and dropping to the 25-27% range for the remainder of the period. As a result of reported financial and licensing difficulties, the Allegheny Power System (which includes Potomac Edison) may be unable to construct two generating stations planned to come online in the years 1983-1987. Based on the utility's demand projections, this contingency could cause available capacity over those years to fall as low as 10.9% below peak demand.

Chapter II - Air Impact

Of the five major pollutants emitted by all sources in Maryland, power plants contribute negligible amounts of carbon monoxide and hydrocarbons, about 30% of the NO_x, 32% of the particulates and 69% of the sulfur oxides.

For the three main power plant pollutants (NO_x, particulates and SO_x,), the air quality is as follows: For particulates, the general areas of Baltimore City and the Potomac River valley near Bloomington are in violation of Federal Ambient Air Quality Standards. All areas are in compliance with standards for sulfur and nitrogen oxides. However, for photochemical oxidents (for which NO_x is a precursor), the areas near Baltimore and Washington have been declared non-attainment areas.

Various methods of sulfur oxide emission control have been analyzed for availability and cost. Comparative costs indicate no major difference (for a new plant) between the use of flue gas desulfurization, starting with high sulfur coal, physical coal cleaning and the use of low-sulfur coal. The use of scrubbers can also generate substantial amounts of waste, (for example, 200 tons/hour for a 1000 MW plant burning 3.5% sulfur coal using a lime scrubber).

The Gaussian plume model, in view of its central role in the prediction of air quality, has been tested using measurements at Maryland power plants. The model has been found to be generally accurate to a factor of two, given flat terrain, low to moderate distance extrapolations, and moderate winds. The limitations on model accuracy in conditions other than these are discussed.

The implications of the Clean Air Act Amendments of 1977 upon the siting of power plants are discussed. Because of provisions related to the Prevention of Significant Deterioration (PSD) and non-attainment areas, the size and potential locations of new coal-fired power plants may be limited. In particular, the designation of a Class I area in or near Maryland could severely limit the potential for siting a 1000 MW coal-fired plant by creating a 40-80 mile "exclusion" zone surrounding the area. Because of the large area of influence of coal-fired plants, the implications of PSD-related growth limitations will lead to competition for use of the available increments within the State. Similarly, the interstate nature of air pollutant transport may lead to competition and dispute between states.

Chpater III - Aquatic Impact

Power plants can cause aquatic impact in several ways: (1) by entraining fish eggs, larvae or prey organisms into a cooling system where they are subjected to thermal, mechanical and chemical stresses; (2) by impinging adult and juvenile fish and crabs on intake screens; and (3) by discharging heat and chemicals into receiving waters.

Cumulative impact has been examined by salinity/habitat zone. Dividing the aquatic habitat into three general areas, we can draw the following conclusions:

Mesohaline (5-19 ppt)

Because of the high reproduction rates of the plankton and good tidal mixing at existing plants, depletion of plankton populations has not occurred. Spawning occurs throughout the Bay for the species of fish present here, so local depletions are insufficient to decrease Bay populations. Impingement totals are small compared to mortality due to other sources. In addition, efforts to reduce these totals are now underway at all three existing plants, Calvert Cliffs, Morgantown, and Chalk Point. Habitat modification effects, usually more subtle in nature, have minor, localized impacts as described in this chapter. Coupled together, the power plant monitoring studies show a low cumulative impact on the mesohaline environment.

Tidal Fresh/Oligohaline (0-5 ppt)

The major area of concern within this region is the impact of cooling water withdrawals upon the nursery and spawning areas of striped bass and other anadromous species. Possum Point and Vienna have the highest potential for impact. New facilities planned for this region (Douglas Point, Summit and Vienna) would increase withdrawals. The overall impact upon striped bass due to entrainment drops from an estimated 6.6 percent entrainment (upper bound) of the eggs and larvae spawned in the Maryland portion of the Bay at present to an estimated 3.4 percent (upper bound) after 1987. The addition of Douglas Point and Summit is more than off-set by the retirements of the once-through cooling units at Vienna. No impingement data is available at any of the present plants; however, degraded water quality at the Baltimore and Washington plants appears to have severely restricted fish populations in these waters. Similarly, habitat modification effects or depletion of plankton would be difficult to detect. Ongoing studies should help to quantify these effects at the existing Maryland plants. The proposed plants are expected to have no major impacts in the areas of impingement or habitat modification due to the small amount of water withdrawn.

Riverine

No impact is expected from entrainment and impingement. Studies of possible habitat modification due to the discharge of heated effluent are now underway at both of the existing plants in this region. These studies are expected to be completed during 1979.

Chapter IV - Radiological Effects

The Calvert Cliffs Nuclear Power Plant, owned by Baltimore Gas and Electric Company, is the only operating nuclear power plant in Maryland. No other nuclear generating stations are scheduled to begin operations within the next ten years.

Spent reactor fuel is accumulating at Calvert Cliffs because the Federal government has halted commercial reprocessing, and has not yet developed its own plans for taking over the job of disposal. By the end of 1978, there will be a total of 216 spent fuel assemblies stored at the plant. BG&E has received permission from the Nuclear Regulatory Commission to expand the capacity of their spent fuel storage pool to 1056 assemblies. This will provide sufficient storage to continue plant operations through 1984, by which time it is hoped that the Federal government can begin accepting spent fuel from commercial reactors.

Discharges of radioactivity from the power plant have been small fractions of the quantities and concentrations allowed, never reaching 10% of any of the various limitations imposed by the Operating License.

Environmental monitoring in the vicinity of the plant has shown the radiation dose to the public from plant operation to be quite small. Calculations from the reported release rates yield 0.2 mrem whole body dose and 0.6 mrem skin dose for the calendar quarter of maximum release.

Radioactivity discharges to the Chesapeake Bay have resulted in detectable concentrations of Ag-110m, Co-58 , and Co-60 in sediments and shellfish. The area yielding samples with detectable concentrations of plant effluents extends for roughly six miles up and down the western shore, with maximum values found at the plant discharge area. The radiation dose to an individual eating 29 dozen oysters and 15 dozen crabs (5 kg of each) taken from the plant discharge area would be about 4/1000 mrem whole body dose and 0.2 mrem gastrointestinal tract dose (about 0.007% and 0.5% of the applicable guidelines, respectively.)

Comparison of these power plant-induced doses with the fluctuations in natural radiation dose already experienced by the public indicates that the power plant effects are insignificant. For instance, detected variations in the natural radioactivity of the soils from place to place in Calvert County can create differences in annual radiation dose of 30 mrem, and different construction materials have been shown to cause changes of 14 mrem/year in the interior dose rates of buildings. These natural variations are tens of times greater than the maximum doses resulting from Calvert Cliffs Power Plant.

Although operations to date provide an insufficient basis to predict radiological impact of the Calvert Cliffs Plant over its operational lifetime, available data indicate that the plant should continue to operate with insignificant radiological impact, well within all applicable guidelines.

Chapter V - Socio-Economic Impacts

The construction of an electric generating station may have socio-economic effects upon the community in which it is located. Among the possible effects during construction are changes in population leading to strains in housing, schools, employment, transportation, and increased demands on local government services. The scale of the effects vary according to the population base of the county in which the plant is located and the distance of the site from major metropolitan areas.

Increased demands for county and municipal public services also varies during the construction period. In some instances the increased cost of public services can result in large budget deficits at both the county and municipal level as construction period revenue increases fail to keep pace with service costs. In the study case of potential Eastern Shore power plant sites, annual municipal budget deficits were estimated to range from 3% to 21% for nuclear plant construction. The same study projected the largest county deficit at 4%, with other counties experiencing revenues and expenditures which were essentially in balance.

After a new plant starts operation, the tax revenues to county governments are on the order of several million dollars per year or greater depending on plant size and local tax rates, and the service costs are small.

Chapter VI - Other Impacts

Cooling towers can be an environmentally-acceptable alternative to once-through cooling. Basically, a cooling tower exchanges consumptive water use and possible terrestrial effects for effects in the aquatic environment. There also is a loss in energy production. Because the balance of these effects is site-specific, each plant location should be examined to determine the appropriate cooling system.

Studies at Chalk Point indicate that salt deposition from the natural draft cooling tower would not exceed 8 kg/ha/month (7 lb/acre/month) at the maximum point. Experiments to determine the sensitivity of corn, soybeans, or tobacco indicated that no significant effects occurred at deposition rates below 20 kg/ha/month (18 lb/acre/month).

The routing of transmission lines deals with effects that may have aesthetic, ecological, health and physical implications. The aesthetic effects generally include trade-offs between visibility and environmental protection. Ecological effects can be both positive and negative and must be evaluated on a case-by-case basis. The electrical effects are now well understood and are potentially significant only for locations within, or extremely close to the right of way. The health effects remain an area of controversy, mainly due to differing medical results from U.S. and Soviet studies.

Although the withdrawal of groundwater is relatively high at power plants compared to most other industrial sources, due to the relatively sparse usage of the deep aquifers they have tapped and the large area occupied by the power plant sites, there has been no significant impact upon present wells near these plants. However, if a major increase in withdrawals from the Magothy aquifer were to occur in the neighborhood of Chalk Point, there could be significant impact upon users of the Magothy aquifer in that area.

RECOMMENDATIONS

1. It is recommended that the present requirement in law for a 10-year plan from each electric utility be extended to 15 years. Present trends indicate that 8-10 years are required to locate, license, and construct a fossil-fueled plant and 10-15 years are required for a nuclear plant.

2. Although studies to date indicate that there have been no significant cumulative impacts on the aquatic environment due to power plants, studies of long duration are needed to validate that initial conclusion. Cumulative impact assessment by salinity habitat zone should continue for the purpose of finding any cumulative impact thresholds that might impose limits on the siting, design or operation of future power plants.

3. Issues arising under the Federal Clean Air Act Amendments will seriously impact the State's ability to carry out orderly planning for the siting and construction of new fossil-fueled power plants. These issues include the allocation of "Prevention of Significant Deterioration" (PSD) increments among all emitting facilities, the requirement for emissions offsets for new sources locating in or near non-attainment areas; and the interstate nature of air pollutant transport and resulting regulatory issues. Since all emitting facilities are affected, not just power plants, the resolution of these issues must be achieved on a comprehensive basis. As initial steps the following actions are recommended:

    a. A policy board should be convened to devise alternative strategies for allocating PSD increments among new sources. This board would be composed of representatives of the Departments of Economic and Community Development, Health and Mental Hygiene, State Planning, and Natural Resources.

    b. An offset bank exchange center should be established that would facilitate the purchase of emissions offsets for new sources wishing to locate near non-attainment areas or near areas where the PSD increment has been fully utilized.

    c. The State should pursue the creation of a multistate planning council, for example, through the National Governor's Association, whose purpose will be to:

        (i) provide a clearinghouse for information on all sources likely to contribute significantly to pollution levels across State boundaries as well as regulatory actions related to those sources.

(ii) provide a forum for the resolution of disputes between states on consumption of PSD increments by interstate transport of pollutants.

4. Current State law prohibits storage of spent fuel in Maryland for longer than two years. As amended during the 1978 General Assembly Session, this effectively prohibits storage of spent fuel at Calvert Cliffs beyond January, 1980. In view of the lack of facilities to accept this spent fuel anywhere in the nation, legislation to resolve this dilemma must be considered.

   Since the findings of Chapter 4 indicate no environmental impact from the additional storage, it is recommended that legislation to allow continued storage at Calvert Cliffs be enacted during the 1979 session pending action of the Federal government to provide permanent storage.

5. Although available data indicate that the Calvert Cliffs plant should be able to continue to operate with insignificant radiological impact, operations to date provide an insufficient basis to predict radiological impact of the plant over its operational lifetime. Therefore the State should continue its program of data collection to provide for continuing cumulative impact assessment.

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CHAPTER I

ENERGY AND ELECTRIC POWER

Since the publication of the first Cumulative Environmental Impact Report in 1975, a number of major changes have occurred which will affect the generating requirements and plans of Maryland's electric utilities. The recession and steep rise in fuel prices which occurred after the oil embargo caused a decline in the use of electric power in 1974. The use of electric power leveled off as Maryland's ecomony recovered and fuel price moderated. Growth in the use of electricity has resumed, but at a lower rate than before. In consideration of the earlier decline in usage and the current lower average annual rates of growth, Maryland utilities have delayed or postponed the addition of some generating units, and have rearranged the construction schedule of others.

This chapter reviews the status of electric utilities in Maryland. The purpose of the chapter is to provide an analysis of future electric generating requirements. Because the demand for electric power in Maryland and the types of generating capacity selected by Maryland utilities are strongly influenced by national economic and energy trends and policies, the chapter begins with a description of the organization of the electric utilities in Maryland. Next national energy trends and projections are discussed, followed by the current projections of electric power demand for the Maryland electric utilities, and analyzes their plans for new generating capacity over the next twenty years. This analysis includes a discussion of likely trends in both plant types and siting. The chapter concludes with a discussion of the adequacy of the future supply of electricity in Maryland.

A second function of this chapter is to make available a compendium of information on historic and projected electric power use and generation in Maryland.

The analysis of electric power supply in Maryland is based on traditional central generating station systems. Energy conservation and decentralized alternative energy systems are not discussed explicitly, but are to some extent implicit in the Power Plant Siting Programs independent demand forecasts. Maryland's energy conservation and alternative energy programs are managed by another unit of the Maryland Energy and Coastal Zone Administration of which the Power Plant Siting Program is a part.

A. Electric Utilities in Maryland

Most of Maryland's electrical customers receive power generated by one of five major electric utilities. All except Conowingo have power plants in Maryland.* These utilities are:

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* Two utilities, Susquehanna Power Company (a subsidiary of Philadelphia Electric) and Pennsylvania Electric Company have hydroelectric facilities in Maryland at Conowingo Dam and Deep Creek Lake, respectively. Neither utility has customers in Maryland.

- Baltimore Gas and Electric Company, serves 714,633 residential customers, with 1977 peak load of 3,588 MW and total megawatt hour sales of 15,462,000 MW.

- Conowingo Power Company, a non-generating subsidiary of the Philadelphia Electric Company, serves 20,982 residential customers, with 1977 peak load of 85 MW and total megawatt hour sales of 419,926 MWh.

- Delmarva of Maryland, a subsidiary of Delmarva Power and Light Company, serves Delaware and portions of Maryland and Virginia. Delmarva of Maryland serves 68,816 residential customers with a 1977 peak load of 400 MW and total megawatt hour sales of 1,726,551 MWh. Delmarva also provides generation for municipals and cooperatives located in its service territory.

- Potomac Electric Power Company, serves portions of Maryland, Virginia and the District of Columbia. PEPCO serves 249,384 Maryland residential customers with a 1977 system peak load of 3,857 MW and total megawatt hour sales of 8,342,247 MWh in Maryland, including wholesale sales to the Southern Maryland Electric Cooperative.

- Potomac Edison serves customers in Western Maryland, eastern West Virginia, and northern Virginia. A subsidiary of the Allegheny Power System, Potomac Edison had a 1977 Maryland peak load of 1,018 MW and total sales of 5,604,079 MWh, and serves 107,682 residential customers in Maryland. The Potomac Edison 1977 system peak was 1,486 MW, with system sales of 8,349,010 MWh.

In addition to the major utilities, Maryland is served by a number of municipally-owned utilities ("municipals"), most of which purchase power from the generating companies at wholesale rates and distribute that electricity within their service areas, and by rural electric cooperatives ("cooperatives") which are owned by their customers and most of which also purchase their power from the generating companies. The municipals and cooperatives operating in Maryland are:

Municipals	Cooperatives
Bèrlin Centreville Easton Hagerstown St. Michaels Thurmont Williamsport	Accomack - Northampton Electric Cooperative Choptank Electric Cooperative Somerset Rural Electric Cooperative Southern Maryland Electric Cooperative

Of the municipals, only Easton has generating capability. Easton currently has 32.6 MW capacity, and is included in this chapter as part of the Delmarva Group, consisting of the Delmarva Power and Light Company system, Dover, Delaware (a municipal system), and Easton.

The service territories of the Maryland utilities are shown in Figure I-1.

In addition to generating their own power, utilities may arrange for purchases of power from plants owned by other utilities to which they are connected by a transmission system. Such purchase may be made on a "firm power" basis as a substitute for a utility's own capacity, or may be made either on an emergency basis (such as the temporary failure of one of its own units or a level of demand larger than anticipated) or on an "economy" basis. Economy sales and purchases are exchanges between utilities which permit the utility to select the least expensive electricity available at a given moment either from its own generating units or from units owned by another company. Utilities can function as a power "pool," in which all of the plants of the member companies are treated as belonging to a single entity -- the "pool" -and power is sent out to a given utility from the most efficient unit (i.e., the unit with the lowest cost of generation) available at that moment, regardless of ownership or location.*

Four of the five Maryland electric companies belong to the PJM Interconnection, a power pool made up of 11 utilities in Maryland, Pennsylvania, New Jersey and Delaware.** (Potomac Edison, the fifth major utility is a subsidiary of the Allegheny Power System, which operates its three subsidiary companies as a fully integrated system in a manner analogous to a power pool.) These utilities interchange electricity between each other on an economy basis. As a result, the extent to which each utility generates its own electricity is largely a function of the availability of less expensive generation elsewhere in the system at a given moment in time. This, in turn, depends on the efficiency of the plants owned by each utility and on the pattern of demand experienced by each company at a given moment.

Figure I-2 illustrates sales and purchases to other utilities for BG&E and PEPCO (1), for the calendar years 1976 and 1977. The Figure shows the change in the relative amounts of purchases and sales of power from other utilities (mostly within the PJM power pool) which occurs over an annual demand cycle, particularly the shift towards purchases of power during the summer months during which these two utilities experience their highest level of demand. The figure also shows the shift towards deliveries of power to the pool as a large amount of capacity becomes available from new units with lower capital costs, as when the second BG&E Calvert Cliffs nuclear unit came on-line

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* Transmission costs are incorporated into the send-out decisions.

** The PJM members are: Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power & Light Company, Philadelphia Electric Company (of which Conowingo is a subsidiary), Potomac Electric Power Company, Public Service Electric and Gas Company, UGI Corporation

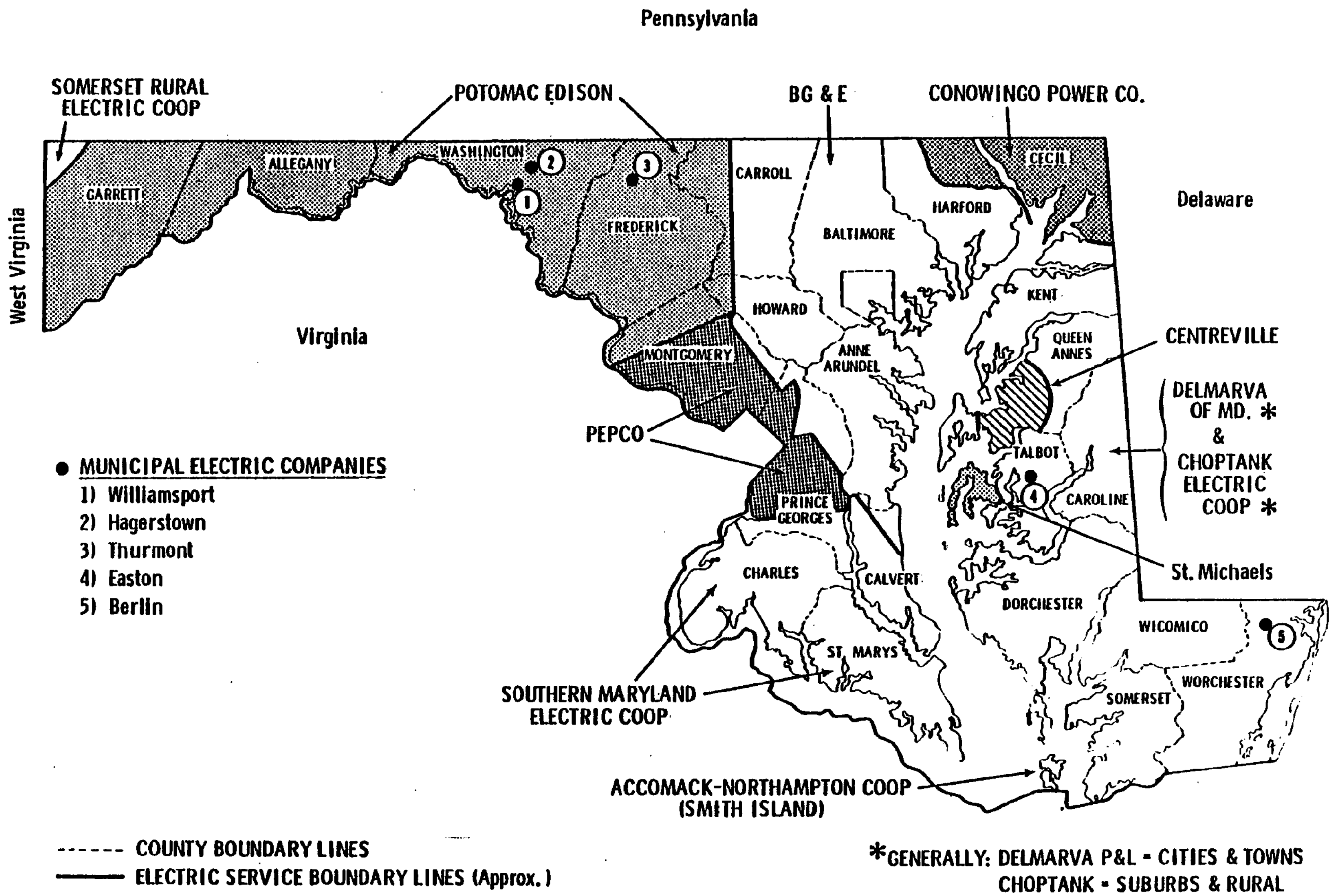

Figure I-1. Service territories of Maryland electric utilities

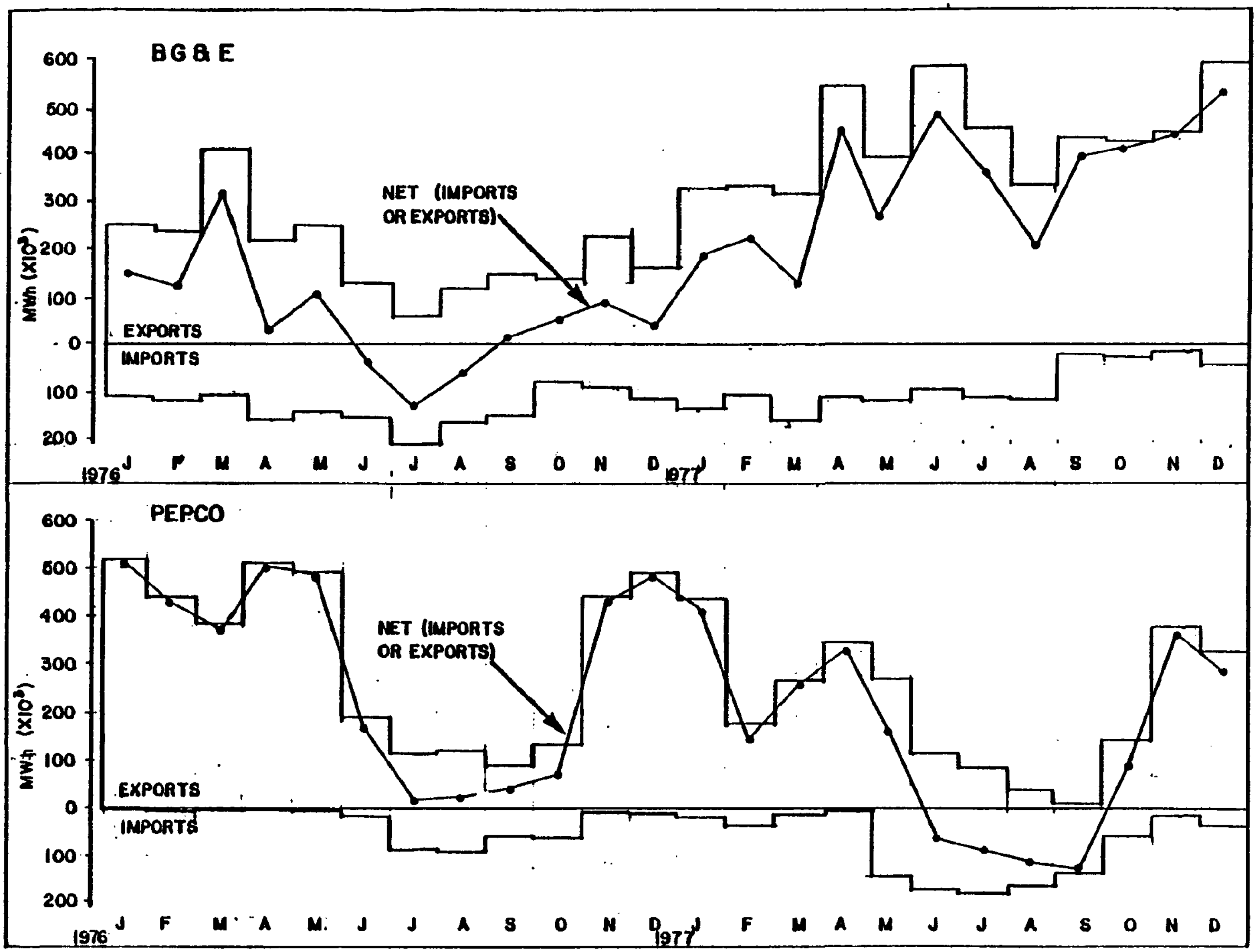

Figure I-2. Imports and exports of electric power by BG&E and PEPCO, 1976-1977 in April of 1977, or during winter months during which these utilities experience lower levels of energy use by their own customers.

Historically, Maryland has been a net importer of electric power. In recent years, imports have ranged from a low of 1.2% of total electric power use in 1977 to a high of 13.9% in 1975. BG&E, Potomac Edison, Delmarva of Maryland, and Conowingo have historically been net importers of power, while PEPCO, Pennsylvania Electric (owner of hydroelectric capacity at Deep Creek Lake), and Susquehana Electric (owner of hydroelectric capacity at Conowingo Dam) have been net exporters. Table I-1 gives the net imports and exports of power for Maryland by utility from 1967 to 1977 (2).

In addition to whatever pool arrangements they may make, U.S. utilities were required by the Federal Power Commission* to form regional Electric Reliability Councils. Formed as a consequence of the 1965 Northeastern power blackout, the purpose of the councils was to develop a level of utility interconnection and system reliability adequate to reduce the likelihood of large-scale power blackouts. These reliability councils serve as planning bodies to coordinate utility generation and transmission planning They do not serve the economy send-out function of power pools. However, the councils do monitor the availability of plants in their own and neighboring territories, they make that information available to member utilities hourly, and they coordinate emergency interchanges.

BG&E, Delmarva, Conowingo (through its parent company, Philadelphia Electric Co.), and PEPCO are members of the Mid-Atlantic Area Council (MAAC), which covers all or parts of Maryland, the District of Columbia, Pennsylvania, New Jersey, Delaware, and the Eastern Shore portion of Virginia. Potomac Edison is a member of the East Central Area Reliability Coordination Agreement (ECAR), which covers the western portion of Maryland, Pennsylvania, and Virginia, all of West Virginia, Ohio, and Indiana, and most of Michigan and Kentucky.

Utility interconnections, either in power pools or in the reliability system grid, raise the question of whether or not a utility generation construction program is required for the utility's own customers or for sales to another utility located elsewhere. The regional reliability council agreements are intended to foster a high level of total system reliability by requiring that each member utility have a level of capacity adequate to serve its own needs, and by providing a level of interconnection of utilities that is capable of transfering power from other utilities into a particular service area in emergencies.** The PJM Power Pool agreement, which is designed to provide its members access to the least expensive electricity at any point in time, has a similar clause requiring that its members own enough generating capacity to maintain a given level of reliability, and includes a surcharge for continuing purchases necessitated by factors such as inadequate generation capacity.

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* Now the Federal Energy Regulatory Commission (FERC) of the U.S. Department of Energy.

** This ability to obtain power from other companies actually reduces the amount of capacity a utility must own in order to achieve a given level of reliability.

Table I-1. Imports and exports of electricity to and from Maryland by utility, 1967-1977, millions of MWh[a]

Year	Baltimore Gas & Elec.	Conowingo	Delmarva Power & Light[b]	Pennsylvania Electric	Potomac Edison (c)	PEPCO[d]	Susquehanna Electric	Total State of Md.
1967	-1,251,673	-184,240	-407,715	27,988	-974,259	3,725,179	1,811,472	2,746,762
1968	-463,019	-205,142	-484,876	22,850	-1,137,495	2,536,890	1,506,695	1,776,916
1969	-984,212	-250,341	-516,592	16,425	-1,372,891	1,058,753	1,265,288	783,555
1970	-1,146,112	-259,983	-680,646	29,655	-2,407,265	1,515,313	1,790,275	-1,158,749
1971	-1,881,874	-281,841	-751,188	34,652	-3,180,728	2,254,070	1,663,910	-2,142,985
1972	-3,145,610	-300,186	-503,684	39,733	-3,422,097	4,885,510	2,163,320	-283,000
1973	-4,286,781	-319,786	-340,331	32,860	-3,802,468	4,161,602	2,038,271	-2,516,621
1974	-3,617,297	-326,553	-472,106	31,420	-3,683,085	5,677,575	1,848,381	-591,778
1975	-5,711,684	-332,967	-1,095,230	35,868	-3,630,108	5,047,380	2,185,789	-3,605,478
1976	-3,479,120	-374,773	-885,152	23,059	-4,964,629	6,175,803	1,971,017	-1,608,762
1977	850,077	-391,677	-1,414,885	20,862	-5,236,555	3,893,618	1,899,644	-370,679

(a) Data indicates net exports; negative figure indicates imports.

(b) Includes only DP&L of Maryland and Easton.

(c) Includes imports and exports from Maryland portion of service territory only.

(d) Includes PEPCO sales to PEPCO service territory in Virginia and the District of Columbia as exports.

In reviewing certificate applications for Maryland's utilities, it has been the policy of the Maryland Public Service Commission to evaluate the need to expand capacity to meet projected future demand on the basis of the anticipated requirements of the utility's own service territory. The interconnections and power pools to which Maryland utilities belong can assist in improving utility performance and reliability. Ultimately, however, generation plans are developed by an individual utility on the basis of the requirements of its own service territory, and are judged by regulatory authorities on the same basis.

The next section of this chapter evaluates national and regional trends in total energy and electricity. In that framework, the final sections describe electrical generation trends and plans for each of the Maryland utilities at the service territory level.

B. National Energy Trends

Prices and supplies of competing sources of energy are determined within the framework of national and regional markets. Policy decisions made at a national or even an international level influence those markets, and as a consequence they shape energy options available in Maryland. It is helpful, therefore, to begin the discussion of Maryland's energy situation by describing the national energy framework within which Maryland functions.

The major primary sources of energy in the United States are petroleum, natural gas, coal, hydroelectric power and nuclear power. Figure I-3 shows the changes that have taken place in the consumption of these primary sources of energy since 1960. Table I-2 presents similar data in tabular form, with energy sources shown as a percentage of U.S. energy use for each year (3).

Two major trends in the table and figure are worth noting. First, total domestic energy use has grown almost without interruption, increasing by 70% over the past 17 years. However, during the recession which followed the dramatic oil price increases after the oil embargo of 1973, total U.S. energy consumption fell for the first time since the recession of 1958-1959. But as the data in Table I-2 show, growth in energy use resumed in 1976, coinciding with the end of the 1974-75 recession.

The second point to note in Table I-2 is the two major changes that have taken place in the composition of the U.S. energy mix. The first major change is the longterm replacement of coal by oil and, until recently, by gas. The energy share coming from coal has been taken up by the growth in the use of gas, especially for home heating purposes, and by the growth in the use of oil, especially for home heating, and for industrial and electric utility fuel use. Figure I-4 shows clearly the extent to which coal has been replaced by oil and natural gas over the past 75 years (4). The data in Table I-2 and Table I-3 suggest that in the post-embargo years since 1973 the role of coal nationally may be reversing again, particularly for electric power generation purposes (3).

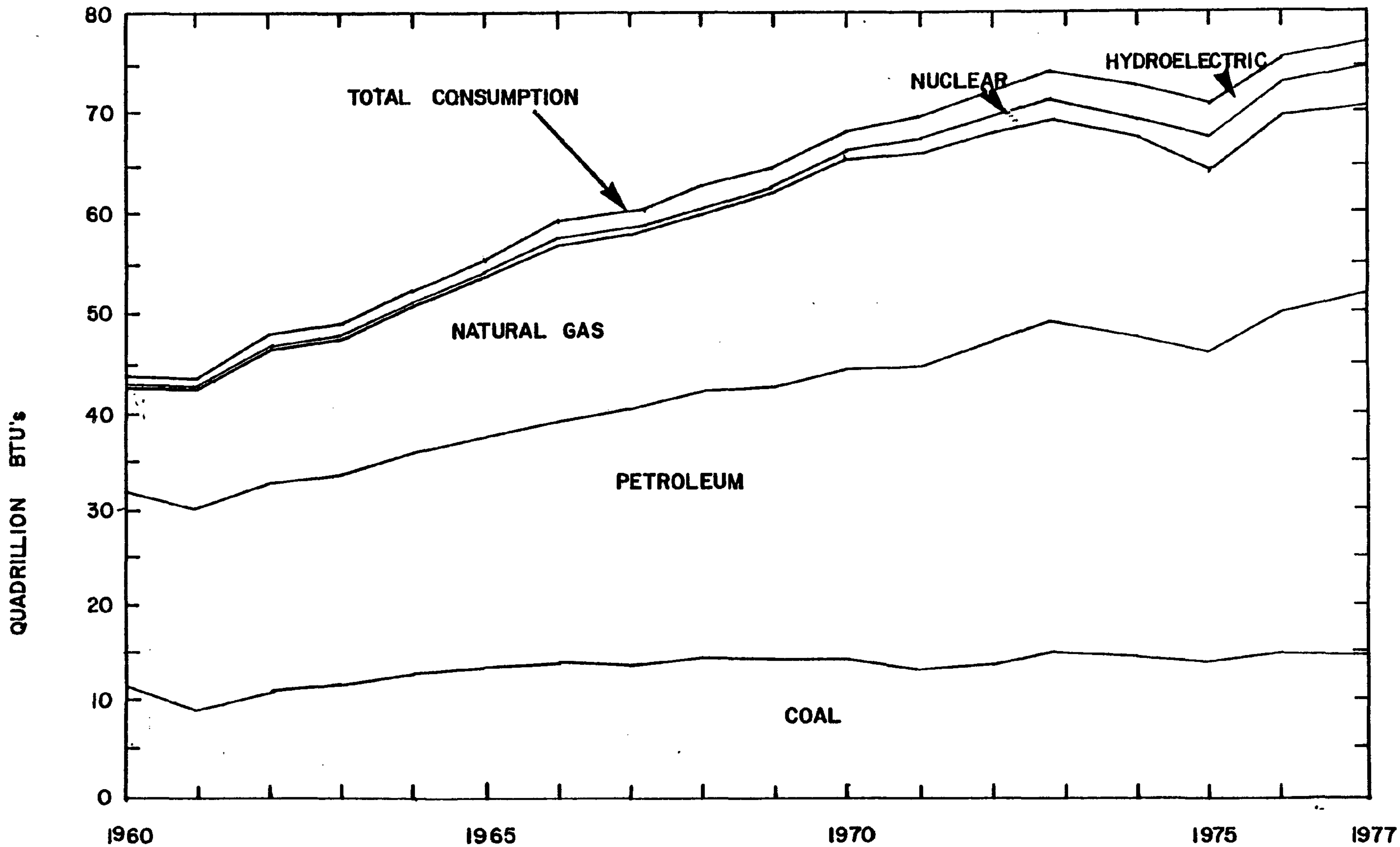


Figure I-3. U.S. total energy consumption by primary source, 1960-1977

Table I-2. U.S. energy consumption by primary energy type, 1960-1977

Year	Total Energy Consumption		Coal		Petroleum		Natural Gas		Nuclear		Hydroelectric	
	Quads*	% Change Annual	Quads	% of Total	Quads	%	Quads	%	Quads	%	Quads	%
1960	44.5	3.3	10.1	22.7	20.0	44.9	12.7	28.5	< 0.1	< 1.0	1.6	3.6
1961	45.3	1.7	9.9	21.9	20.5	45.3	13.2	29.1	< 0.1	< 1.0	1.6	3.5
1962	47.4	4.6	10.2	21.5	21.3	44.9	14.1	29.7	< 0.1	< 1.0	1.8	3.8
1963	49.3	4.0	10.7	21.7	22.0	44.6	14.8	30.0	< 0.1	< 1.0	1.7	3.4
1964	51.2	3.9	11.3	22.0	22.4	43.8	15.6	30.5	< 0.1	< 1.0	1.9	3.7
1965	53.3	4.1	11.9	22.3	23.2	43.5	16.1	30.2	< 0.1	< 1.0	2.0	3.8
1966	56.4	5.8	12.5	22.2	24.4	43.3	17.4	30.9	0.1	< 1.0	2.0	3.5
1967	58.2	3.3	12.3	21.1	25.3	43.5	18.3	31.4	0.1	< 1.0	2.3	4.0
1968	61.7	6.0	12.7	20.6	27.1	43.9	19.6	31.8	0.1	< 1.0	2.3	3.7
1969	64.9	5.2	12.7	19.6	28.4	43.8	21.0	32.4	0.1	< 1.0	2.6	4.0
1970	67.1	3.3	12.7	18.9	29.5	44.0	22.0	32.8	0.2	< 1.0	2.6	3.9
1971	68.3	1.8	12.0	17.6	30.6	44.8	22.5	32.9	0.4	0.6	2.8	4.1
1972	71.6	4.8	12.4	17.3	33.0	46.1	22.7	31.7	0.6	0.8	2.9	4.1
1973	74.6	4.1	13.3	17.8	34.9	46.8	22.5	30.2	0.9	1.2	3.0	4.0
1974	72.6	(2.6)	12.9	17.3	33.5	44.9	21.7	29.1	1.2	1.6	3.3	4.4
1975	70.6	(2.8)	12.8	18.1	32.7	46.3	19.9	28.2	1.8	2.5	3.2	4.5
1976	74.4	5.3	13.7	18.4	35.1	47.2	20.3	27.3	2.0	2.7	3.0	4.0
1977	75.8	2.0	14.1	18.6	37.0	48.8	19.6	25.9	2.7	3.6	2.4	3.2

*Quads = quadrillion BTU's = 10^{15} BTU's

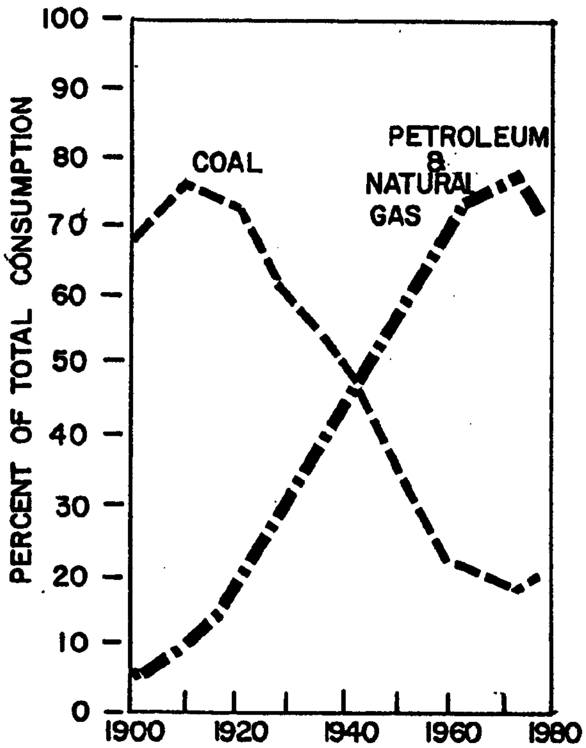


Figure I-4. Proportion of total U.S. energy supplied by coal vs oil and natural gas, 1960-1977

Table I-3. Electricity generation by fuel type - U.S. (millions of kilowatt hours and percentages of total generation)

Year	Total Net Production 10^6 kWh	Coal		Petroleum		Natural Gas		Nuclear		Hydroelectric		Other	
		10^6 kWh	%	10^6 kWh	%	10^6 kWh	%	10^6 kWh	%	10^6 kWh	%	10^6 kWh	%
1960	753,350	403,067	53.5	46,105	6.1	157,970	21.0	518	0.1	145,516	19.3	174	0.0
1961	792,039	421,871	53.3	47,120	5.9	169,286	21.4	1,692	0.2	151,850	19.2	220	0.0
1962	852,314	450,249	52.8	46,983	5.5	184,301	21.6	2,270	0.3	168,283	19.8	228	0.0
1963	916,793	493,927	53.9	52,001	5.7	201,602	22.0	3,212	0.3	165,755	18.1	296	0.0
1964	983,990	526,230	53.5	56,954	5.8	220,038	22.4	3,343	0.3	177,073	18.0	352	0.0
1965	1,055,252	570,926	54.1	64,801	6.1	221,559	21.0	3,657	0.4	193,851	18.4	458	0.0
1966	1,144,350	613,475	53.6	78,926	6.9	251,151	21.9	5,520	0.5	194,756	17.0	522	0.1
1967	1,214,365	630,483	51.9	89,271	7.4	264,806	21.8	7,655	0.6	221,518	18.2	632	0.1
1968	1,329,443	684,904	51.5	104,276	7.9	304,433	22.9	12,528	0.9	222,491	16.7	811	0.1
1969	1,442,183	706,001	48.9	137,847	9.6	333,279	23.1	13,928	1.0	250,193	17.3	935	0.1
1970	1,492,971	675,199	45.2	179,376	12.0	366,619	24.5	21,806	1.5	249,090	16.7	881	0.1
1971	1,612,593	714,680	44.3	218,622	13.5	374,027	23.2	38,105	2.4	266,300	16.5	859	0.1
1972	1,749,629	772,857	44.1	272,550	15.6	375,735	21.5	54,091	3.1	272,613	15.6	1,783	0.1
1973	1,860,440	848,987	45.7	312,940	16.8	340,804	18.3	83,334	4.5	272,081	14.6	2,294	0.1
1974	1,867,103	829,973	44.5	299,363	16.0	320,055	17.1	113,976	6.1	301,032	16.1	2,704	0.2
1975	1,917,638	852,968	44.5	288,908	15.1	299,772	15.6	172,506	9.0	300,047	15.6	3,437	0.2
1976	2,036,487	943,879	46.3	319,518	15.7	294,419	14.5	191,108	9.4	283,680	13.9	3,883	0.2
1977	2,124,078	985,450	46.4	357,889	16.8	305,357	14.4	250,883	11.8	220,435	10.4	4,063	0.2

The second change is the more recent decline in the proportion of the energy share contributed by natural gas since 1971, when gas contributed 32.9% of the U.S energy supply. By 1976, the share had dropped to 27.3%, a decline in market share of 5.6 percentage points in only 5 years. That relative decline occurred as total U.S marketed production declined from its 1972 record production of 22.1 trillion cubic feet of gas to 19.9 trillion cubic feet in 1976 -- a 10% production decline in 4 years. The decline in gas usage has occurred as gas users, especially industrial customers subject to winter curtailments, have switched to other fuels and as new customers, such as residential customers who would have been gas users, have been forced by moratoria on new gas connections to find alternative sources of energy. In both cases customers have largely turned either to the use of oil or to the use of electricity.

Figure I-5 and Table I-3 show the changes which have occurred nationally since 1960 in the fuel mix used in generating electricity (3). The most obvious change that has occured has been the relative increase in the role of oil, compared to the relative decline in generation by all other fuels except nuclear. This is especially true of coal, which had provided over half (51.5%) of U.S. electric energy as recently as 1968, but which provided only 44.1% by 1972, only four years later. The portion of total electricity generation which had been based on coal shifted to other fuels, principally oil: during the same period, the oil portion of this fuel mix almost doubled from 7.9% of total generation to 15.6%. The absolute amount of oil-fired generation more than doubled, growing from 104,276 million kWH in 1968 to 272,550 million kWH in 1972.

The rapid decline in the relative use of coal was the result of state and Federal air pollution legislation and regulation, principally the Clean Air Act Amendments of 1970. Utilities switched boilers from coal to oil, particularly in urban areas with poor air quality. A large percentage of the new units which were brought on line were also oil-fired. This trend was particularly marked in the heavily urbanized Northeast.

Table I-4 shows the fuel mix distribution for each region of the U.S. (5). The data in the table show fuel mixes for 1960 and 1974, and the Federal Energy Administration's (now part of the U.S. Department of Energy) projection for the 1985 fuel mix, prepared in 1976. As Table I-4 demonstrates, the fuel mix used to generate electricity varies greatly by region. Changes in state and federal energy and environmental policies, as well as in relative energy prices, can significantly affect trends in the fuel mix used by the utilities in the regions in different ways. Air pollution requirements in the urbanized and industrialized Northeast, as well as trends in operating costs, resulted in the dramatic decline in the relative share of coal in New England, which dropped from 50.3% of generation in 1960 to only 7.4% in 1974, and the more modest decline in the Middle Atlantic region, including Maryland, where the coal share dropped from 69.3% in 1960 to 42.7% in 1974.

In response to the 1973 oil embargo, the post-embargo oil price increases and national energy legislation, these trends have begun to change. Table I-3 showed what appears to be the start of an increase in the market share of coal at the national level. Recent legislation, including the Energy Supply and Environmental Coordination Act of 1974 and the Power Plant and Industrial Fuel Use Act of 1978, a portion of the Carter Administration's National Energy

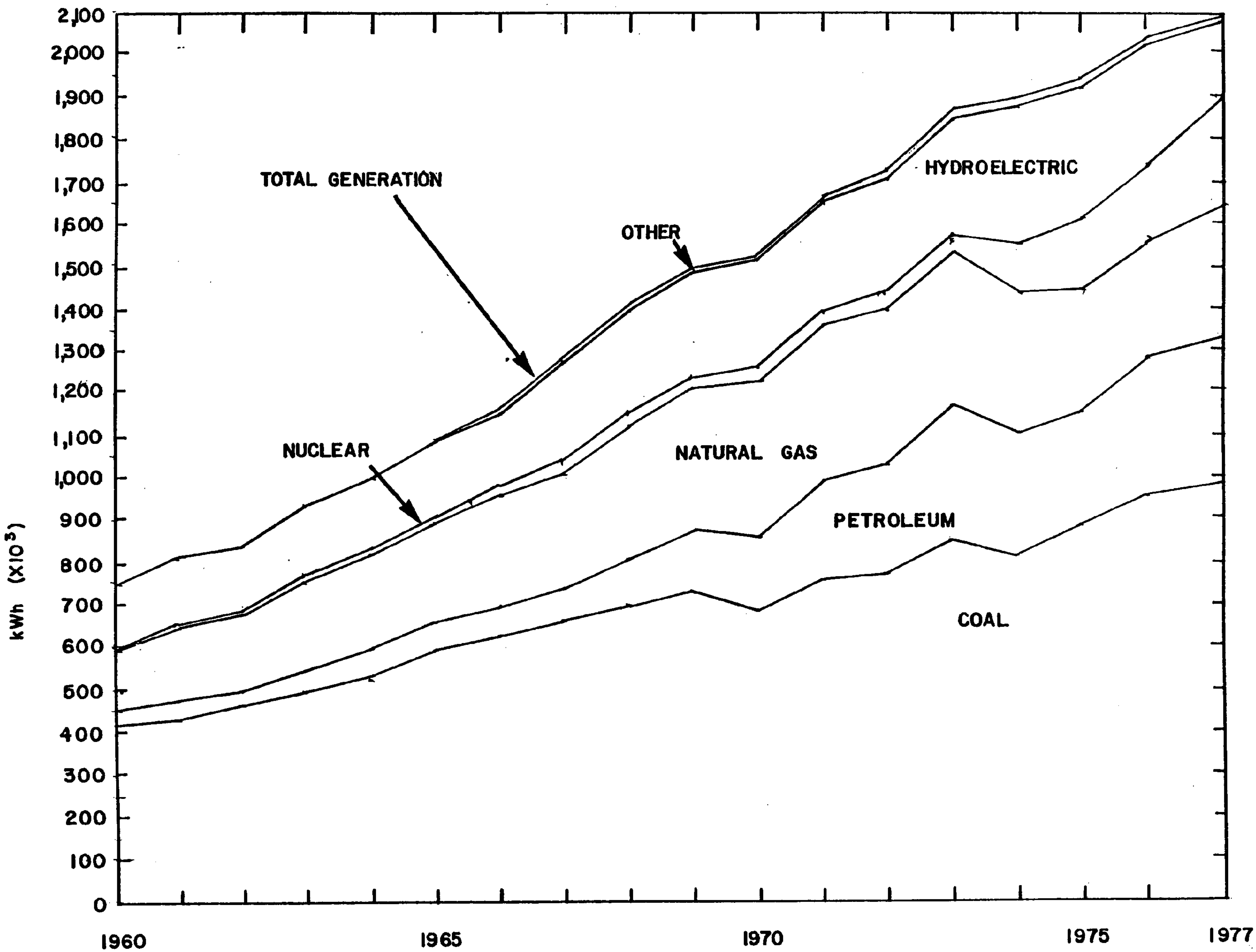


Figure I-5. U.S. electric power generation fuel mix, 1960-1977

Table I-4. Change in electric generation fuel mix, by region, 1960-1985

Region	Percentage of Total Generation for Region														
	1960					1974					1985				
	Coal	Oil/Gas	Nuclear	Hydro	Other	Coal	Oil/Gas	Nuclear	Hydro	Other	Coal	Oil/Gas	Nuclear	Hydro	Other
New England	50.3	31.7	0.1	17.9	-	7.4	61.3	24.4	6.9	-	26.8	28.4	41.0	3.9	-
Middle Atlantic	69.3	18.5	0.2	12.0	-	42.7	36.2	8.5	12.6	-	47.9	13.6	29.9	7.3	1.2
East North Central	93.5	3.8	0.2	2.5	-	82.0	8.7	8.3	1.0	-	66.4	5.8	26.3	0.6	1.0
West North Central	40.3	46.9	-	12.6	0.2	54.4	27.2	7.7	10.7	-	70.1	4.9	17.2	7.7	-
South Atlantic	66.3	20.2	-	13.5	-	54.9	32.5	7.4	5.2	-	52.6	10.3	32.0	7.3	1.2
East South Central	74.5	5.5	-	20.0	-	76.5	5.4	3.6	14.5	-	50.8	4.5	37.3	7.4	-
West South Central	-	95.7	-	4.3	-	3.0	92.6	0.2	4.2	-	20.6	55.3	22.8	1.4	-
Mountain	11.8	36.6	-	51.6	-	46.3	23.2	-	30.5	-	48.7	16.9	14.9	15.2	3.7
Pacific	-	42.0	-	58.0	-	1.7	27.8	2.8	66.7	1.0	4.7	19.9	10.2	62.2	2.5
Nation	53.5	27.1	-	19.3	-	44.5	33.2	6.0	16.1	0.1	45.4	16.1	26.1	11.5	1.0

Plan, is intended to reinforce this trend. This legislation permits the Department of Energy to require utilities and other large users to convert boilers from oil to coal, and to require that new boilers be fueled by coal. The Congressional Budget Office (CBO), in its review of President Carter's proposed energy legislation, projected that U.S. domestic use of coal would increase from 681 million tons in 1976 to 1,066 million tons in 1985 under current national policy and price estimates, and to 1,229 million tons in 1985 under the President's proposals (6). Table I-5 summarizes these projections, which are based on estimates of the growth in the demand for electricity. According to the CBO estimates, the National Energy Plan is not likely to produce major changes in 1985 coal use by electric utilities.

The data in Table I-4 also include projections of the future fuel mix used by the electric utilities in each region of the country. The projections were prepared in 1976 by the Federal Energy Administration, and are based on a complex set of assumptions concerning future fuel availability and prices, and the economic and physical ability of utilities to respond to the changing fuel conditions. Nationally, those projections indicate a large relative shift away from oil-fired generation towards nuclear, with a relatively constant coal share. For the Mid-Atlantic region (which includes Maryland), where the use of imported oil is extensive, the relative shift away from oil is anticipated to be substantial, with significant increases in the shares of coal and nuclear generation.

Table I-6 presents the additions to total generating plant projected by more recent forecast (7). The forecast is the National Electric Reliability Council's (NERC) summary of the generation expansion plans of the U.S. electric utilities for the next 10 years, summarized by electric utility region. The two NERC regions which include Maryland are MAAC and ECAR.

The projections shown in Tables I-4 and I-6 contain important policy implications. It is now national policy to encourage and require the use of coal and nuclear power to replace oil. The NERC compilation of utility expansion plans shows a shift away from oil and gas generation in favor of nuclear and coal generation. At both the national and regional levels, however, the shifts projected by the utilities in NERC (Table I-6) are not as pronounced as had been anticipated by the FEA (Table I-4). The major reason for the much smaller shift away from oil and gas projected by the NERC utilities is the smaller amount of planned new nuclear and coal generating capacity. This results in a significantly higher share of generating capacity being born by oil and gas than assumed by FEA. This difference is even greater in the NERC regions which include Maryland than they are in the country at large.

The differences between the fuel mix projected by the FEA and the fuel mix reflected in current construction plans reported by NERC can be explained to a great extent by the difficulty of altering basic plant designs for plants actually under construction or in advanced planning. However, for plants in the early planning stages, utility generating planners can respond fully to new economic and regulatory policy considerations. As will be discussed in more detail for Maryland later in this chapter, capacity additions during the 1988-1997 time period are expected to fully reflect these changes, and show very pronounced changes in the generation fuel mix.

Table I-5. Projected U.S. coal consumption

Consuming Sector	1976	Projected Use, 1985 Current Policy	Projected Use, 1985 Nat'l Energy Plan
Residential/Commercial	6	2	2
Industrial	156	206	360
Electric Utility	459	768	777
Export	60	90	90
TOTAL	681	1,066	1,229

Table I-6. National and regional generation expansion plans, 1977-1987

NERC Region*	Coal		Oil		Gas		Nuclear		Hydro		Pumped Storage	
	1977	1987	1977	1987	1977	1987	1977	1987	1977	1987	1977	1987
ECAR	81.8	74.5	9.6	7.5	1.1	0.7	3.3	13.7	0.7	0.5	3.3	2.8
ERCOT	11.3	35.8	0.2	0.1	87.8	52.9	0.0	10.7	0.6	0.4	0.0	0.0
MAAC	34.2	31.8	46.3	36.4	0.5	0.4	14.0	27.0	2.1	2.0	2.9	2.2
MAIN	67.1	55.9	12.4	14.9	0.6	0.2	16.2	27.2	1.2	0.8	2.3	0.9
MARCA	52.1	65.7	15.6	11.0	1.4	0.7	17.1	14.3	13.8	8.3	0.0	0.0
NPCC	7.4	10.5	61.6	50.9	<0.1	<0.1	15.0	28.8	10.6	5.6	5.2	4.3
SERC	50.4	43.6	26.2	17.9	0.2	0.1	13.0	28.8	9.5	6.3	0.7	3.3
SPP	11.9	40.6	12.8	7.9	67.9	35.6	1.9	12.5	4.9	2.7	0.7	0.6
WSCC	18.2	23.3	32.8	23.8	2.9	2.7	2.8	15.9	41.3	30.4	1.3	2.6
NATION	39.2	42.7	25.5	18.3	13.1	7.8	8.4	20.0	11.7	8.4	1.9	2.3

* NERC regions are generally defined as follows:

ECAR - Western Maryland, Pennsylvania, and Virginia, Ohio, West Virginia, Kentucky, Indiana, Michigan
MAAC - Maryland, Pennsylvania, New Jersey, Delaware
ERCOT - Central and Southern Texas
MAIN - Missouri, Illinois, Wisconsin, Northern Michigan
MARCA - North and South Dakota, Minnesota, Iowa, Nebraska; Manitoba
NPCC - New York, New England; Ontario, New Brunswick
SERC - Eastern Virginia, Tennessee, North and South Carolina, Mississippi, Alabama, Georgia, Florida
SPP - Kansas, Oklahoma, Northern Texas, Arkansas, Louisianna, Western Mississippi
WSCC - Montana, Wyoming, Colorado, New Mexico, and all states further West; British Columbia

The likelihood of attaining the projected shifts in production patterns shown in Table I-4 and even Table I-5 is open to some question. Utilities have postponed or cancelled many of the nuclear units assumed in the projections in Tables I-4 and I-6. The data show a drop-off in the number of new nuclear plants coming on line (Table I-7), and the number of new units ordered has shown a similar decline (3).

Part of the drop-off in new plants and new orders can be explained by the falloff in electric power demand during the 1974-1975 recession and to the subsequent rate of growth in the demand for electric power. In response to levels of demand for electricity which were lower than anticipated, many utilities slowed construction schedules or postponed the startup of new construction. In addition however, part of the drop-off in the rate of addition of new nuclear units stems from uncertainty on the part of utilities about such national policy issues as nuclear waste disposal (see Chapter IV). If the trend in Table I-7 continues, it is likely that the national share of generation coming from nuclear power in 1985 and 1990 will be lower than anticipated, and the share from coal and oil correspondingly higher. (The 1978 ten-year capacity and demand forecast prepared by Electrical World (8), a major trade journal, reaches a similar conclusion, and projects an even lower nuclear power share of 18% in 1987.)

It is also likely that the national share of generation coming from coal-fired generating units will be lower than anticipated. Some of the coal-fired capacity assumed in Table I-4, and even in Table I-6, has been postponed or cancelled in response to levels of demand and rates of demand growth that are lower than had been anticipated.

Projections of trends in future fuel mixes are based on projections of future growth in electric power demand, as well as of energy policy, fuel supply, and price trends. National projections of electric energy demand have been made by a number of forecasters representing government, private corporations, and independent consultants. While the estimated growth rates differ, the projections uniformly show a significant reduction in the growth rate, from the more than 7% annually that prevailed in the years from 1945 through 1973. Table I-8 show the results of a number of these forecasts, most of which were prepared in 1976 and 1977.

Projections of future demand at the national level have continued to decline as more experience with higher energy prices has accumulated. Regional electric reliability councils include ten-year forecasts in their annual submissions to the Federal Power Commission. Figure I-6 shows the declines in each successive forecast since the 1973 embargo (9). These forecasts are derived from projections made by each of the nation's utilities, and they vary significantly in the forecasting methodology used.

The changes in forecasts shown in Figure I-6 indicate the degree of uncertainty which has affected recent utility planning, making national forecasting more difficult. From these utility capacity and demand forecasts, however, it is quite clear that the demand for electric power at the national level is expected to grow, although at a slower rate than in the past, and that the generating equipment used to meet this demand is likely to rely less on oil and more on coal and nuclear power than in the past. The reduction in the

Table I-7. U.S. nuclear power capacity expansion

Year	Units Added	Capacity Added, MW
1965	1	16
1966	1	907
1967	- 1	- 35
1968	0	987
1969	3	1,310
1970	3	1,048
1971	5	3,322
1972	5	4,556
1973	9	8,121
1974	9	9,649
1975	10	8,878
1976	3	2,561
1977	8	5,884

Table I-8. Comparison of annual growth rates in U.S. electricity consumption (%/yr)*

Forecast	Demand 77	Starr	SR-37	EEI	NFP	DRI	FEA	IEA	EPP	MOPPS	NERC-FPC
1975-1980											
High	7.9	6.7	8.4	6.1	6.2	6.3	6.3	5.4	6.8	4.1	--
Medium	6.9	5.5	7.4	6.1	5.5	6.6	5.4	--	3.3	--	6.7
Low	6.9	4.7	6.1	5.5	4.5	6.1	5.2	4.4	3.0	3.2	--
1980-1985											
High	6.8	6.7	7.2	6.6	6.2	5.6	6.3	5.3	6.8	4.1	--
Medium	6.0	5.5	5.3	5.4	5.5	5.6	5.4	--	3.3	--	6.2
Low	5.5	4.7	3.2	4.3	4.5	5.6	5.2	4.4	3.0	3.2	--
1985-1990											
High	6.1	6.7	--	5.6	5.5	4.9	6.4	4.3	5.0	4.1	--
Medium	5.3	5.5	--	5.0	4.6	4.7	5.7	--	2.4	--	5.5
Low	4.5	4.7	--	2.8	3.5	4.9	5.3	2.9	1.7	3.2	--
1990-1995											
High	5.8	6.7	--	5.6	5.5	--	6.4	4.3	5.0	4.1	--
Medium	4.8	5.5	--	5.0	4.6	--	5.7	--	2.4	--	5.5
Low	4.3	4.7	--	2.8	3.5	--	5.3	2.9	1.7	3.2	--
1995-2000											
High	5.7	6.7	--	5.6	--	--	--	4.3	5.0	4.1	--
Medium	4.6	5.5	--	5.0	--	--	--	--	2.4	--	--
Low	4.1	4.7	--	2.8	--	--	--	2.9	1.7	3.2	--

Demand 77	Larry J. Williams, et al., Demand 77, EPRI Annual Energy Forecasts and Consumption Model, EA-621-SR (Palo Alto, Calif.: Electric Power Research Institute, 1978).
Starr	Chauncey Starr, "Electricity Needs to the Year 2000," presented to the Subcommittee on Energy Research, Development, and Demonstration; House of Representatives Committee on Science and Technology; Washington, D.C., 1976.
SR-37	Larry J. Williams, A Preliminary Forecast of Energy Consumption Through 1985, SR-37 (Palo Alto, Calif.: Electric Power Research Institute, 1976).
EEI	Edison Electric Institute, Economic Growth in the Future (New York: McGraw-Hill, 1976).
NFP	Mitre Corporation, Need for Power (NFP) Study, Interim Report, prepared for U.S. Energy Research and Development Administration, Washington, D.C., 1977.
DRI	Data Resources, Inc., Energy Review, Summer 1977 (Lexington, Mass.: Data Resources, Inc. 1977).
FEA	Federal Energy Administration, National Energy Outlook (Washington, D.C.: U.S. Government Printing Office, February 1976).
IEA	Institute for Energy Analysis, Economic and Environmental Impacts of a Nuclear Moratorium, 1985-2010 (Oak Ridge Associated Universities, September 1976).
EPP	Energy Policy Project of the Ford Foundation, A Time to Choose (Cambridge, Mass.: Ballinger, 1974).
MOPPS	Energy Research and Development Administration, Market Oriented Program Planning Study, Review Draft (Washington, D.C., 1977).
NERC-FPC	Projections of the National Electric Reliability Council and the Federal Power Commission, as reported in NFP (see above).

*Growth rates are repeated from one five-year period to another where they have only been reported for longer periods.

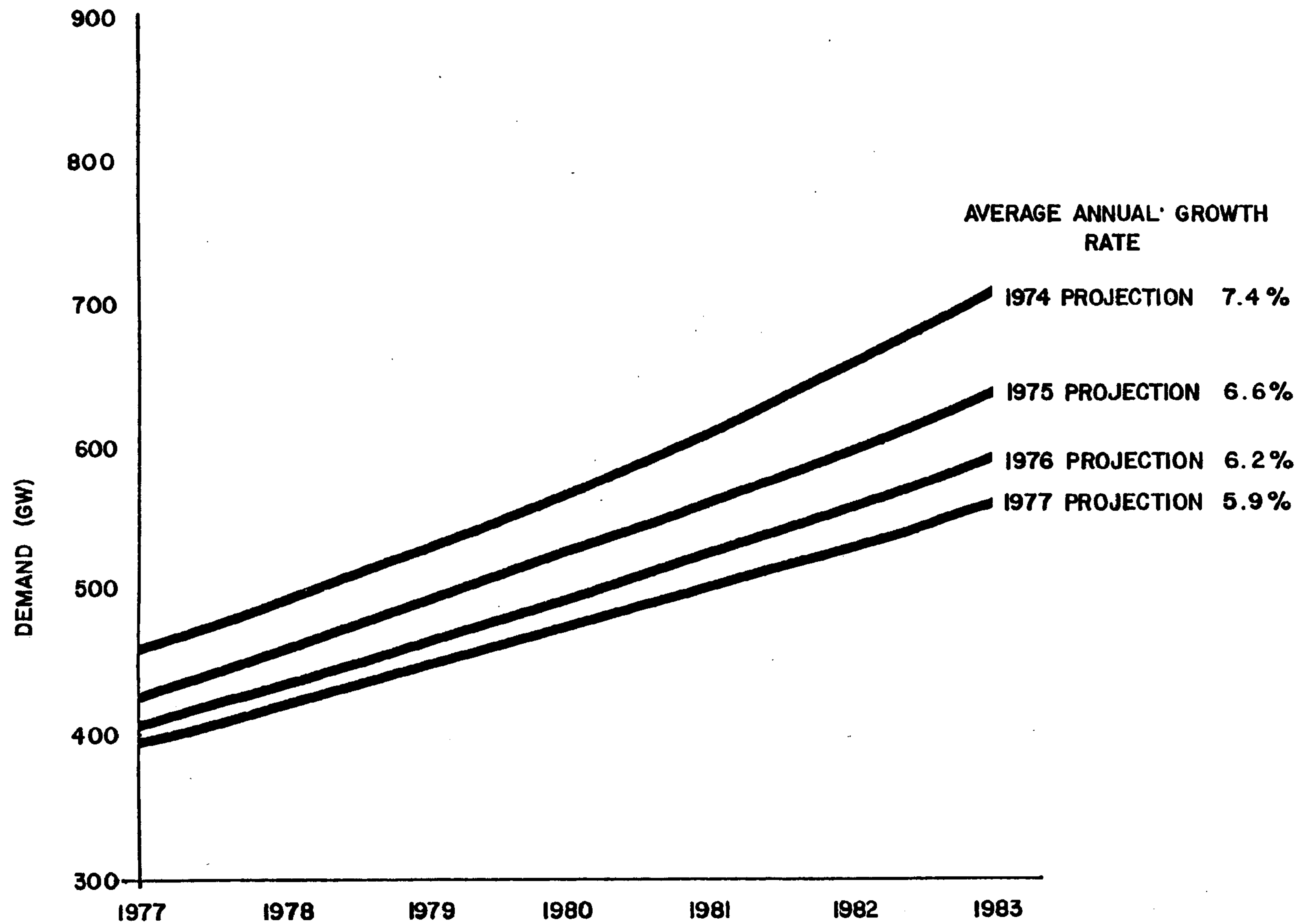


Figure I-6. 1974-1977 projections of peak demand by U.S. electric utilities reliance on oil in favor of coal and nuclear power will be less than had been anticipated by government planners at the Federal level.

C. Maryland: Energy

The demand for and supply of energy in Maryland are driven by the same factors that affect national energy use and supply patterns. Those factors work through the set of conditions that uniquely define the State of Maryland and the Maryland economy. Factors such as the cost of transportation for alternative fuels, the composition of state industry, the age and construction of homes, and the relative level of personal income all influence the way in which Maryland consumers and industries use energy and types of fuels selected to meet those energy needs. The resulting pattern of energy demand and supply, while strongly influenced by national trends, is unique to Maryland and must be evaluated at the state level.

Table I-9 and Figure I-7 present energy flow data for the U.S. and Maryland for 1974, the most recent year for which comparable data are available (10). As can be seen from the table, there are major differences in gross energy supply and conversion between Maryland and the nation at large. The principle and most striking difference is the proportionately large share of total energy coming from oil in Maryland. The important role of oil is seen both in gross energy input for all uses and in the mix of fuels used by Maryland utilities. In both cases, Maryland oil usage is considerably higher than that of the nation as a whole: the proportion of gross oil usage is 36% higher in Maryland than in the nation, and the proportion of oil used in electric generation is almost 240% higher. The importance of oil usage in Maryland is based on the ready availability of formerly inexpensive foreign oil, the distance of population centers from large coal fields and the resulting relatively high transportion costs, and the air pollution problems that exist in Maryland's extensive urban and suburban areas.

D. Maryland Utilities: Past Trends and Future Projections

Public utilities are required by the terms of their franchise to meet customers' demand for electric power. The instantaneous demand for electric power varies by time of day, the day of the week, and by season. In addition, the demand for power exhibits a long-term trend of growth, interspersed with infrequent declines. In order to fulfill the service requirement, utilities must formulate generating expansion plans well in advance. Recent estimates indicate that it may take 8 to 10 years to bring a major coal-fired power plant on line, and up to 13 years to bring a nuclear plant on line. As a result, utilities must plan for changes in capacity over a period significantly in excess of 10 years. The Regional Electric Reliability Councils require that member utilities submit 10 and 20 year generating plans and forecasts, and the Maryland Public Service Commission requires the annual submissions of a Ten-Year Plan (see Appendix A).

There are several important concepts necessary to an understanding and evaluation of the long-range generation expansion plans of Maryland's electric utilities:

Table I-9. Energy Flows, 1974. Entries in percent of gross energy input: U.S., 72.67 x 10^{15} BTU; Maryland, 1.23 x 10^{15} BTU

U.S.

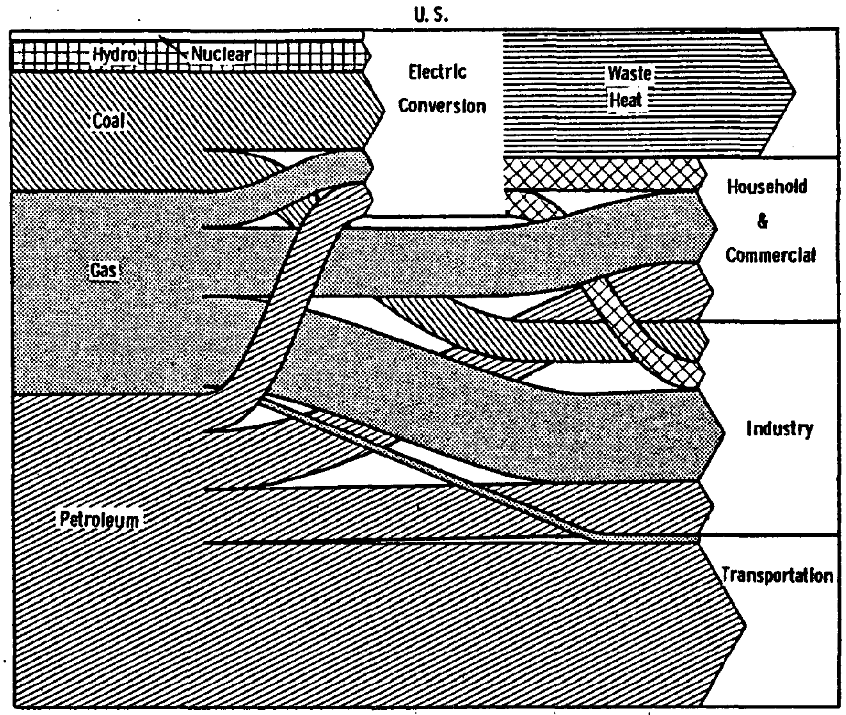
GROSS INPUTS		ELECTRIC CONVERSION		TO END USERS				
Source	Input	To Electric Generation	Electric Output	Source	Input	To Household & Commercial	To Industry	To Transportation
Nuclear	1.7	1.7		Electric	8.8	5.1	3.7	.02
Hydro	4.5	4.5						
Coal	17.7	11.7		Coal	6.1	0.4	5.7	
Gas	29.9	4.8	→ 8.8	Gas	25.1	10.4	13.8	.9
Petroleum	46.1	4.8		Petroleum	40.9	8.4	8.1	24.4
TOTAL	100.0	27.5	8.8		81.0	24.4	31.3	25.4

Unaccounted for (petroleum) = 0.4
In industry sector 0.15 and 4.87 percentage points of coal and petroleum, respectively, go into non-fuel use (chemical feed stock)
Electric conversion efficiency = 8.82/27.52 x 100 = 32.1 percent
Electric energy is 10.9 percent of end user supply
Totals may not check because of independent rounding

Maryland

GROSS INPUTS		ELECTRIC CONVERSION		TO END USERS				
Source	Input	To Electric Generation	Electric Output	Source	Input	To Household & Commercial	To Industry	To Transportation
Nuclear	0	0		Electric	9.9	6.1	3.8	0.06
Hydro	1.2	1.2						
Coal	19.1	9.1	9.9	Coal	10.0	0.1	9.8	0
Gas	16.8	1.1		Gas	15.7	10.4	4.1	0.20
Petroleum	62.9	16.3		Petroleum	46.5	16.0	5.1	26.40
TOTAL	100.0	27.6	9.9		82.0	32.7	22.8	26.6

Unaccounted for and miscellaneous = 0.3
Electric conversion efficiency 9.92/27.64 = 35.9
Electric energy is 12.1 percent of end user supply
Totals may not check because of independent rounding



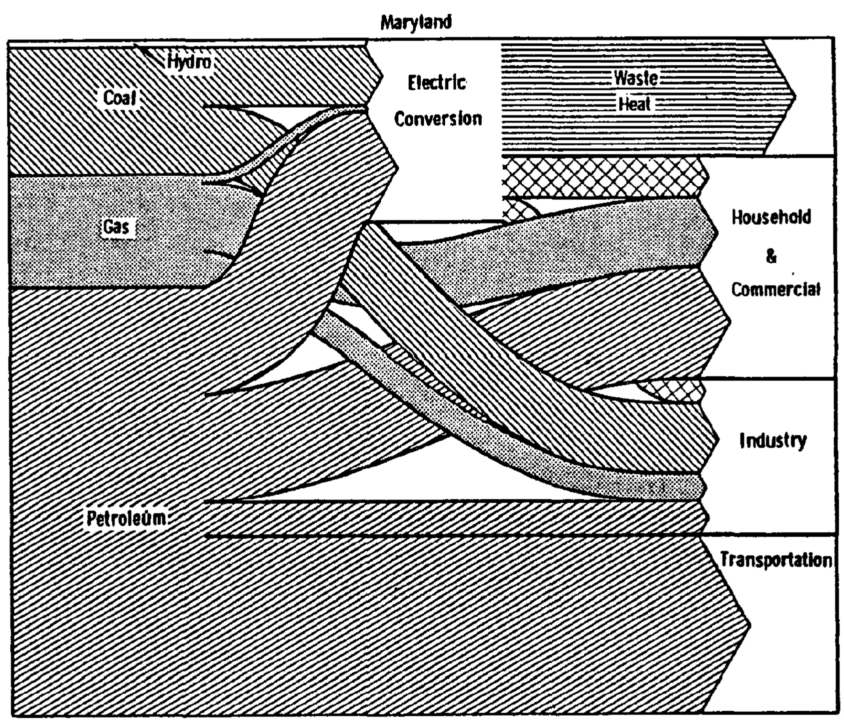


Figure I-7. Energy flows, 1974 percent distribution

- Demand is the amount of electric power required by customers at any given instant in time, usually stated in megawatts (MW) or Kilowatts (kW). One kW is the amount of power needed to light ten 100 watt light bulbs, and a megawatt is 1,000 kilowatts.

- Energy is the amount of electric power consumed over a period of time, usually stated in kilowatt-hours (kWh). One kWh is the amount of electricity required to light ten 100 watt light bulbs for one hour, and a megawatt hour (MWh) is 1,000 kilowatt-hours.

- Peak Demand is the maximum demand experienced during some time interval, such as a day or year. Peak demand in the following tables is the average power used over the 60 minute period of heaviest demand during a given year. Electric power demand varies significantly over a day, week or year, as shown in the one-day "load curve" in Figure I-8. Peak demand for that load curve is approximately 8,500 MW.

- Load Factor is the ratio of the average load (MW) to the peak load during the time period being measured. An annual system load factor, SLFa, is defined as:

$$SLFa = \frac{SEa}{SPLa \times 8760}$$

where: SLFa = annual system load factor
SEa = annual system energy output (MWh)*
SPLa = annual system peak load (MW), and
8760 is the number of hours in a year (8784 in a leap year)

- Capacity Factor is the ratio of the average load (MW) on a plant or entire system to the capacity rating (maximum rated output, MW) of the plant or system for the time period being measured.

- Reserve Margin is the difference between system maximum capacity (MW) and maximum system load, divided by the maximum system load, for any given moment in time. The most commonly used reserve margin is defined at the time of the system peak demand:

$$RMp = \frac{SCp - SDp}{SDp}$$

where: RMp = system peak reserve margin
SCp = system maximum capacity at time of peak
SDp = system peak demand

- Base Load Plants are generating units designed to be run at high efficiency on a continuous basis over long periods of time, and are used over the period indicated by "A" in Figure I-8.

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* Load factor computation is based on system energy output defined to include system losses.

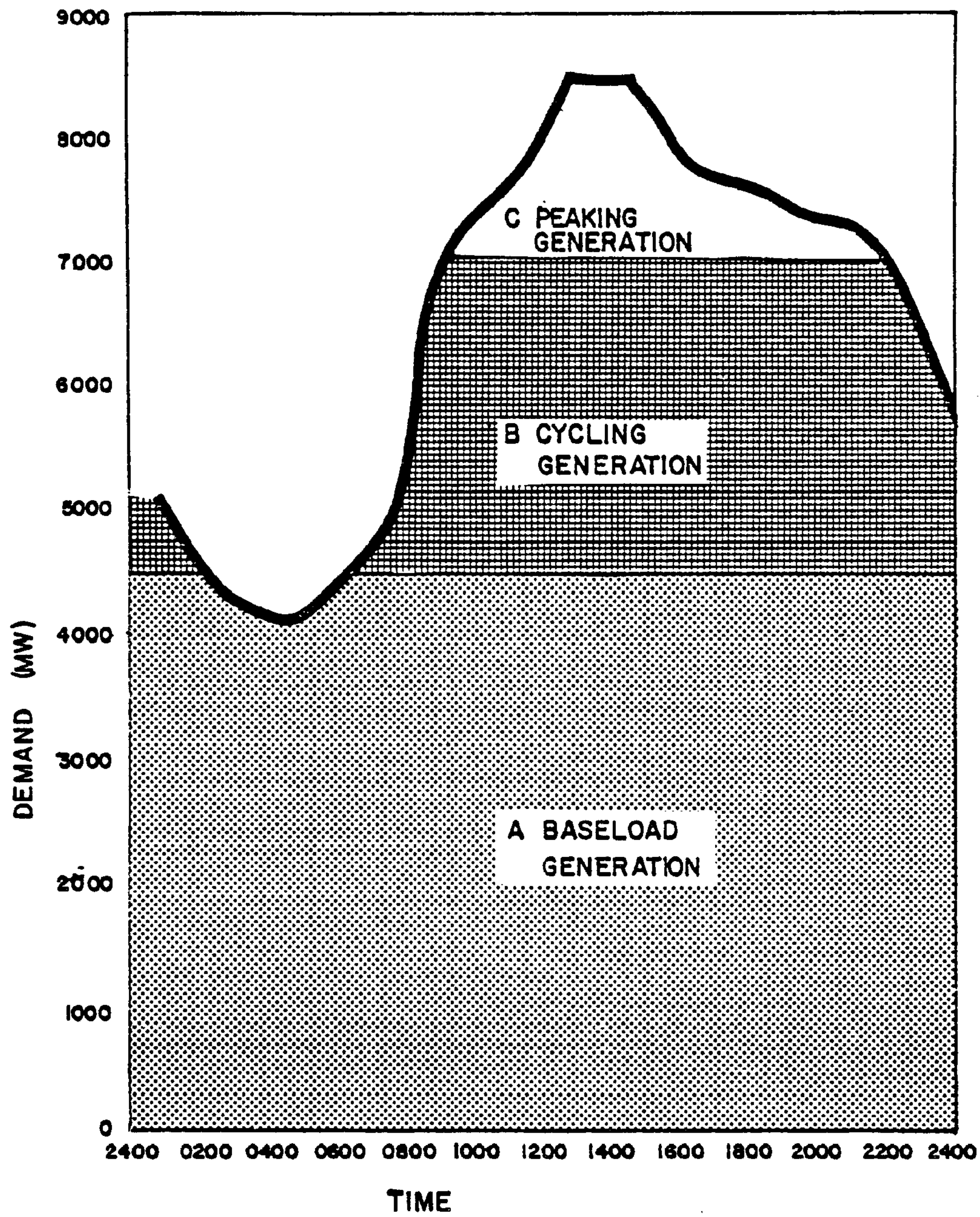

Figure I-8. Hypothetical daily load curve

- Cycling Plants are units designed to operate at relatively high efficiency, but which can be adjusted to meet changing loads and can operate well under relatively frequent on-off cycles. They are generally used in the periods indicated by "B" in Figure I-8.

- Peaking Plants are units designed to operate only for short periods of peak demand, usually for only a brief part of the day during a few months of the year. Efficiency is less important than on-off cycling ability and low capital cost because of the extensive portion of the year during which these plants are idle. They are operated during period "C" in Figure I-8.

The demand for electricity exhibited a remarkably steady growth from the period after World War II through the early 1970's, except for brief periods of slower growth or slight declines during economic recessions. During the period from 1963 to 1973, for example, the annual growth in electric energy used was 7.5% nationally, and 9.7% in Maryland. Figure I-9 shows the sudden change in this pattern of growth which followed the 1973 oil embargo and the subsequent explosive rise in energy prices (8,11).* The rapid energy price increase and the sharp recession which accompanied them produced a 0.1% decline in electric energy use nationally in 1974, and only a relatively slight 1.9% increase in 1975. In Maryland, where imported oil made up a greater share of both the total energy and the electricity utility fuel mix than in the nation generally, the change in the growth in electric energy use was even more dramatic: electric energy use declined by 2.8% in 1974, and grew by only 1.0% in 1975. Not until 1976 did electric power use in Maryland exceed what it had been in 1973. By 1976 growth in electric power use had clearly resumed. Peak demand shows a similar pattern.

Table I-10 shows the pattern of growth in electric power use in Maryland for 1963 through 1977. In the most recent period, covering the years 1976 and 1977, growth in electric power use appeared to indicate a significantly slower rate of growth than in the period prior to 1973, dropping from a 9.7% annual growth rate to 7.4%. In 1977, energy sales nationally grew by 4.3% (see Table I-3), and peak demand grew by 7.1%, very close to the long-term average. In Maryland, energy growth was 5.9%, and noncoincident peak demand grew by 11.9%.**

What is an apparent resumption of prior growth experience must be evaluated carefully, however. The 1977 growth occurred in a year in which both the national and Maryland economies were rapidly recovering from one of the longest and deepest recessions in recent history, and in which most of the contiguous United States experienced record and prolonged July heat. In the period before 1973, these conditions probably would have resulted in national peak demand growth of approximately 10%. The 1977 experience would appear to lend support

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* From 1973 to 1975, the price of imported oil, adjusted for general inflation, rose by 184%, total oil prices (including both domestic and imported oil) by 111%, and coal prices by 88% (12).

** See also Table I-18, at the end of this chapter.

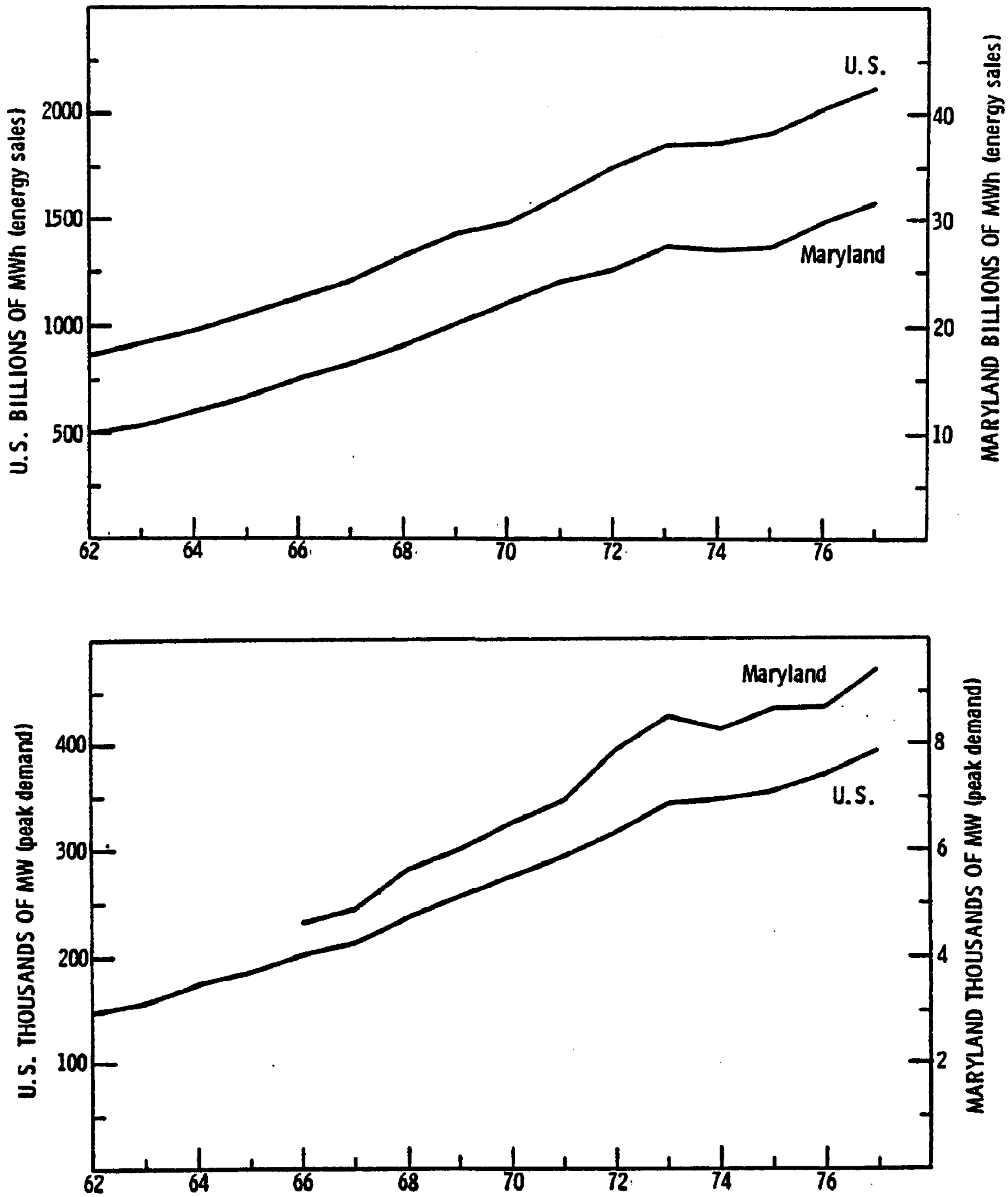

Figure I-9. Maryland and U.S. electric energy sale, 1962-1977,
Maryland and U.S. electric energy peak demand, 1962-1977,
respectively

Table I-10. Electric energy sales in Maryland, 1962-1977*

Year	Maryland (Millions of kWh) Residential	Non-Residential	Total
1962	3,145	6,879	10,024
1963	3,425	7,491	10,916
1964	3,789	8,307	12,096
1965	4,229	9,081	13,310
1966	4,792	10,220	15,012
1967	5,196	11,209	16,405
1968	5,990	12,268	18,258
1969	6,700	13,497	20,197
1970	7,483	15,004	22,487
1971	7,919	16,311	24,230
1972	8,406	17,005	25,411
1973	9,330	18,270	27,600
1974	9,200	17,910	27,110
1975	9,598	17,859	27,457
1976	10,064	19,837	29,901
1977	10,718	20,935	31,653

* Data from Appendix B

to forecasts, such as those in Table I-8, which project a significant reduction in the growth rate in electric power use nationally.

Part of the explanation for the changes in electric energy use that have occurred since 1973 can be found in the changes in energy prices that have occurred since that year -- which also served as a major cause of the accompanying recession. The dramatic fuel price increases of 1973-1974 resulted in significant increases in the price of electricity, as shown in Table I-11 for Maryland (13). The more recent years from 1975 to 1977 experienced far more moderate price increases in electricity (also shown in Table I-11), and have been accompanied by a resumption of growth in electric power usage.

As the data in Table I-10 and Figure I-9 show, recent experience indicates a resumption of growth in electric power use in Maryland. In order to meet that growing demand for electricity, utilities and government agencies must project future levels of demand and develop an appropriate generation expansion plan.

The Maryland Power Plant Siting Act requires that each utility file annually with the Maryland Public Service Commission a Ten-Year Plan showing a forecast of peak load for each of the next ten years, plans for changes in generating capacity and transmission lines, and possible and proposed power plant sites (14). The Public Service Commission compiles these filings into an annual Ten-Year Plan of Maryland Electric Utilities. The 1978 Ten-Year Plan, as amended is included in this report as Appendix A.

Figure I-10 shows the growth projections of each of the successive Plans as well as updates of those projections presented in cases currently before the Maryland PSC (15). These projections, which are compiled directly from the forecasts prepared by the individual utilities, have experienced a pattern of successive reductions in projected growth rates similar to the forecasts reported nationally by the Regional Reliability Councils to the Federal Energy Regulatory Commission (see Figure I-6). Projected average annual growth rates in peak demand for the State have declined with each successive report, from the 9.4% rate reported in the 1973 Plan to the 4.5% rate reported in the 1978 Plan. The most recent projections, taken from cases currently before the Maryland PSC show a growth rate of 4.0%.

Neither the filings by the Maryland utilities nor the Commission's Ten-Year Plan contain any description of the forecasting methods used, supporting documentation, forecasts disaggregated by customer class, or a forecast of energy consumption. However, some of these issues have been explored by the Commission in a case intended to evaluate the adequacy of the utilities' long-range plans (16). Testimony presented by the Maryland utilities in that case indicates that each utility takes a different approach to forecasting. While some of the Maryland utilities use a simple extrapolation of historical trends modified in some way by the judgement of the utility forecaster, others have begun to use a more sophisticated statistical or "econometric" approach.

Over the past two decades, a number of sophisticated techniques have been developed to forecast the future demand for electric power. These approaches utilize statistical or mathematical models to determine the effects of relevant factors on electric energy usage based on historical data. Factors

Table I-11. Electrical bills in Maryland, 1971-1977, in current dollars

Year	Residential[a] Bill	Residential[a] % Change	Commercial[b] Bill	Commercial[b] % Change	Industrial[c] Bill	Industrial[c] % Change
1970	11.63	--	--	--	--	--
1971	12.33	6.0	52.07	--	1,259	--
1972	13.83	12.2	59.05	13.4	1,425	13.2
1973	14.83	7.2	62.75	6.2	1,543	8.2
1974	16.08	8.4	66.42	5.8	1,684	9.1
1975	21.97	36.6	85.44	28.6	2,386	41.7
1976	22.08	0.5	88.29	3.3	2,346	- 1.7
1977	22.78	3.2	92.15	4.4	2,454	4.6
1971-1973		20.3		20.5		22.6
1973-1975		41.1		36.2		54.6
1975-1977		3.7		7.8		2.8

(a) State average bill for 500 kWh per month on January 1

(b) State average bill for 1,500 kWh per month at 12 kW on January 1

(c) State average bill for 60,000 kWh per month at 300 KW on January 1

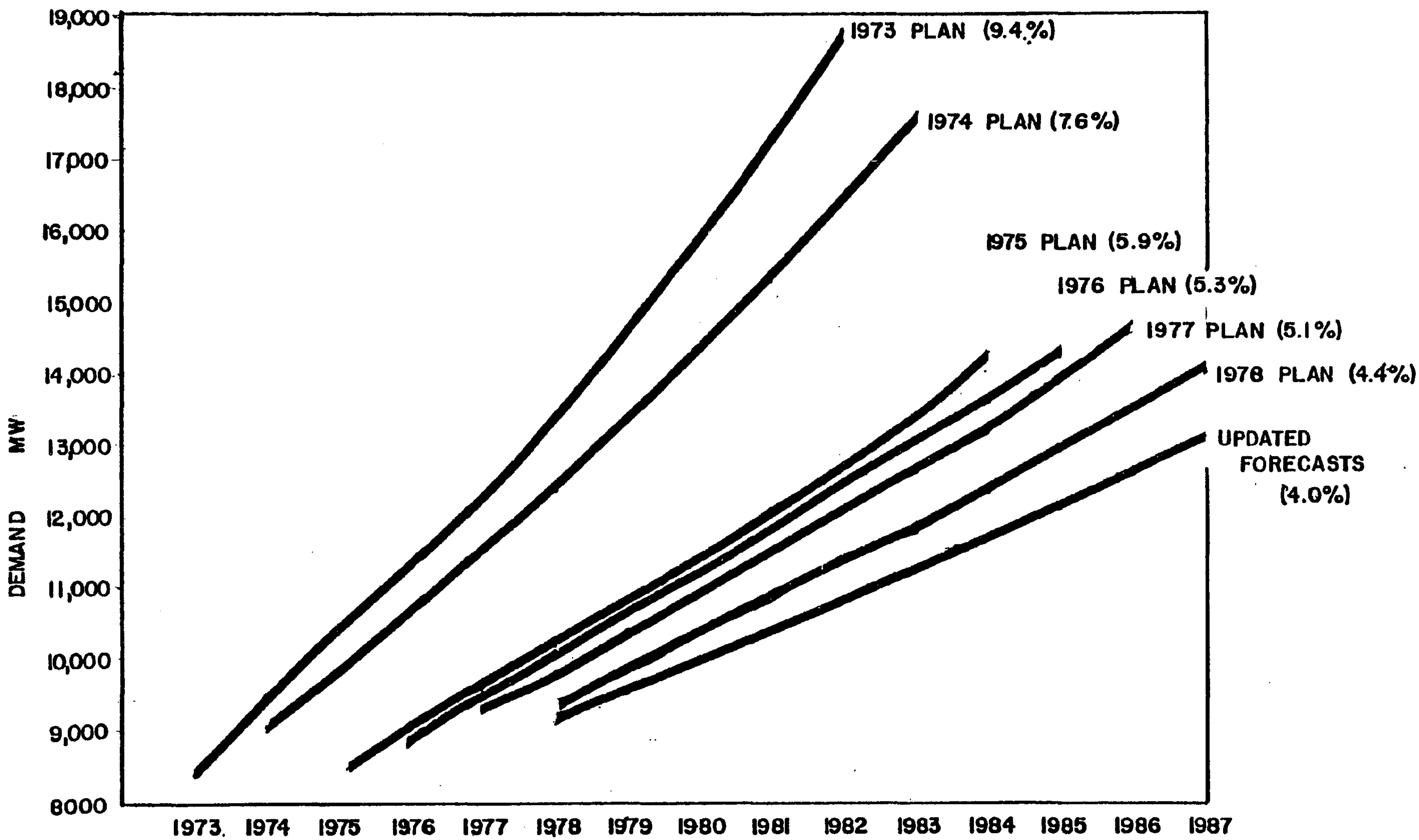

Figure I-10. 1973-1978 projections of peak demand by Maryland electric utilities incorporated in these models usually include the price of electricity and alternative fuels, personal income, industrial production, weather, and population. The models have the advantage of explicitly and quantitatively identifying the relationships between the appropriate factors and the demand for electricity (17).

In conjunction with the Department of State Planning, the Power Plant Siting Program has prepared forecasts for two Maryland utilities (BG&E and PEPCO) as part of a program designed to prepare independent forecasts for all of the major generating utilities. Forecasts for the Allegheny Power System and the Delmarva Power and Light Company will be completed in 1979. The econometric forecasts prepared for PEPCO and BG&E are included in the full state forecast prepared by the Department of State Planning and included in this Report as Appendix B.

Table I-12 presents the energy and peak demand forecast from the Department of State Planning for the years through 1987. As shown in the last line in Table I-12, total electric consumption in Maryland is expected to grow by 5.07% annually over the next ten years. Peak demand for the State is expected to grow by 3.33%. While this growth rate represents an increase from the 2.57% anticipated for the 1977-1980 period and from the negligible growth experienced during the 1975-1977 period (see Table I-18 at the end of this Chapter and Table B-5g of Appendix B), it represents a significant reduction from the 9.3% annual growth rate experienced from 1966 to 1972.

Table I-12 also includes a column showing an estimated load factor for the State as a whole. A state-wide load factor is not appropriate for planning purposes, since capacity decisions are made separately by each utility. The State load factor is included here only as a general indication of likely over-all trends in capacity usage.

As can be seen from the Table, growth in energy consumption is expected to exceed the growth in peak demand over the 1977-1987 forecast period. The implication of this relatively slower peak load growth, and the accompanying improvement in the load factor estimate from .38 to .45 over the same period, is that on a statewide basis, power plant capacity of the Maryland utilities will be more fully utilized than it is now. Should system demand forecasts indicate that this trend will continue, then the State may require future expansion of relatively more efficient base-load capacity.* This conclusion will be more fully explored below.

Figure I-11 shows the demand forecast for each of the Maryland utilities reported in the Department of State Planning report in Appendix B. The figure shows the noncoincident peak demand for each utility, and accumulates them for a state total.

System reliability considerations require that each utility possess generating capacity in excess of its projected peak load at any given moment in time, as a margin of safety in the event that system load is greater than forecast, or in the event of an unanticipated unit outage. The reserve margin

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* Capacity planning decisions are made on the basis of an analysis of alternative generating plan options on electric utility revenue requirements.

Table I-12. Projected energy sales and peak demand in Maryland, 1977-1987 (a)

Year	Energy (MWh)			Peak Demand (MW)	State Load Factor(b)
	Residential	Non-Residential	Total		
1977 (actual)	10,717,522	20,934,984	31,652,506	9,438	0.38
1980	11,989,620	24,857,772	36,847,392	10,186	0.41
1985	15,625,985	31,541,607	47,167,592	12,179	0.44
1987	17,392,838	34,494,714	51,887,552	13,098	0.45
Average Annual Growth Rates					
1977-1980	3.81	5.89	5.20	2.57	
1980-1985	5.44	4.88	5.06	3.64	
1985-1987	5.50	4.58	4.88	3.70	
1977-1987	4.96	5.12	5.07	3.33	

(a) Data from Appendix B

(b) The load factor estimates produced here are computed on the basis of energy sales, rather than on the basis of system energy net of losses ("net energy for load") properly used to compute the load factor of an electric utility.

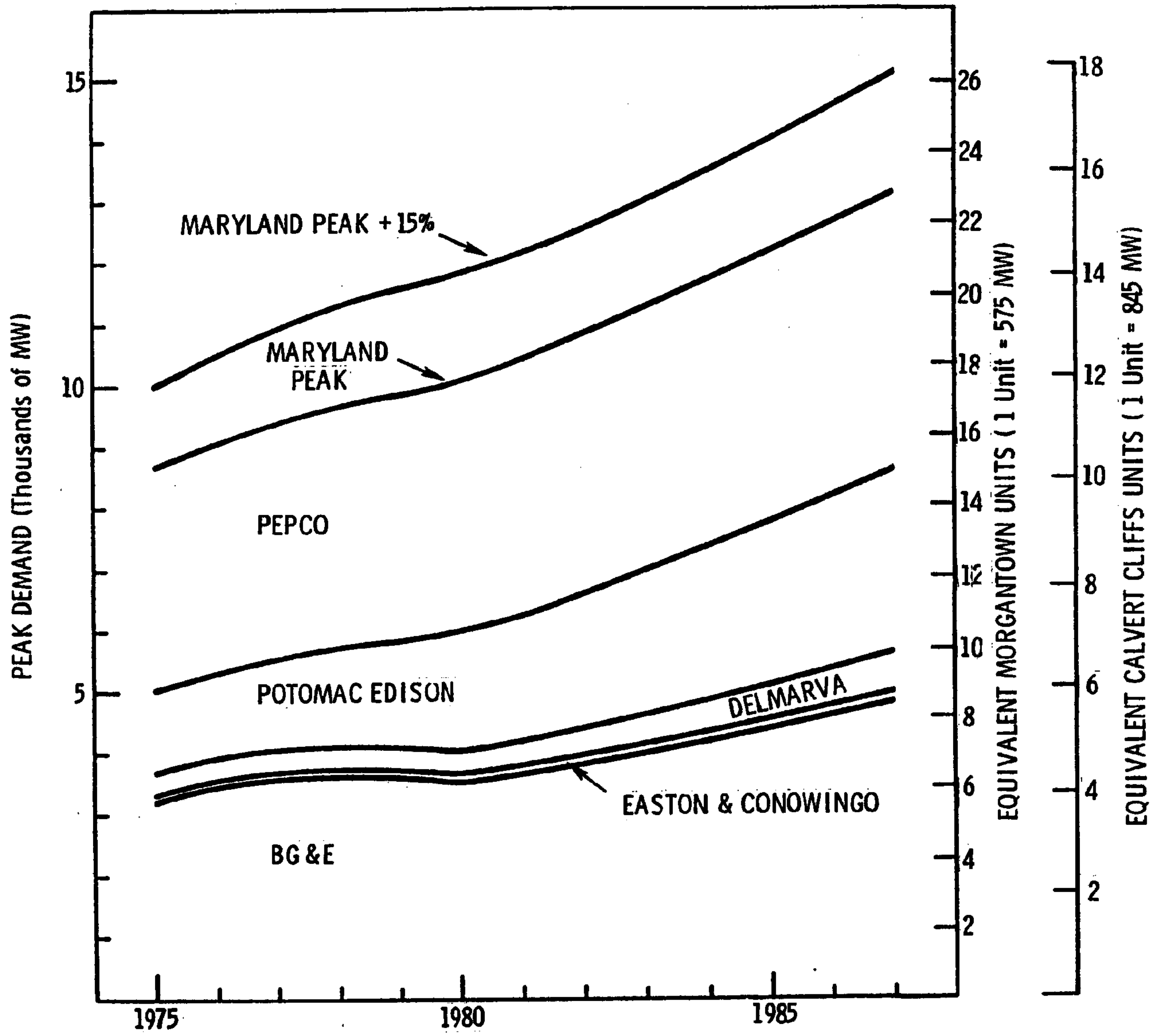


Figure I-11. Peak demand forecast for State of Maryland, 1977-1987 required by reliability council or power pool agreements varies for each utility, and is a function of the operating record of the utility's generating plant and the extent of its interconnections with other utilities, as well as a function of the level of demand. For planning purposes, the desired level of reserve capacity is usually considered to be from 15% to 20% above peak demand.

A 15% reserve margin has been applied to the State peak demand in Figure I-11, and the total capacity required to meet Maryland's peak demand and reserve requirements shown in the top line of Figure I-11. For comparison, the right-hand scale of the Figure shows the number of units the size of Calvert Cliffs (845 MW nuclear) or Morgantown (575 MW coal) that are equivalent to this level of generating capacity. By 1987, Maryland's peak demand is forecast to be the equivalent of 15.5 Calvert Cliffs units or 23.2 Morgantown units. With a 15% reserve margin, the total generating requirement is the equivalent of 17.8 Calvert Cliffs units (an increase over present capacity of 3.3 units) and 26.2 Morgantown units (an increase of 5.8 units).

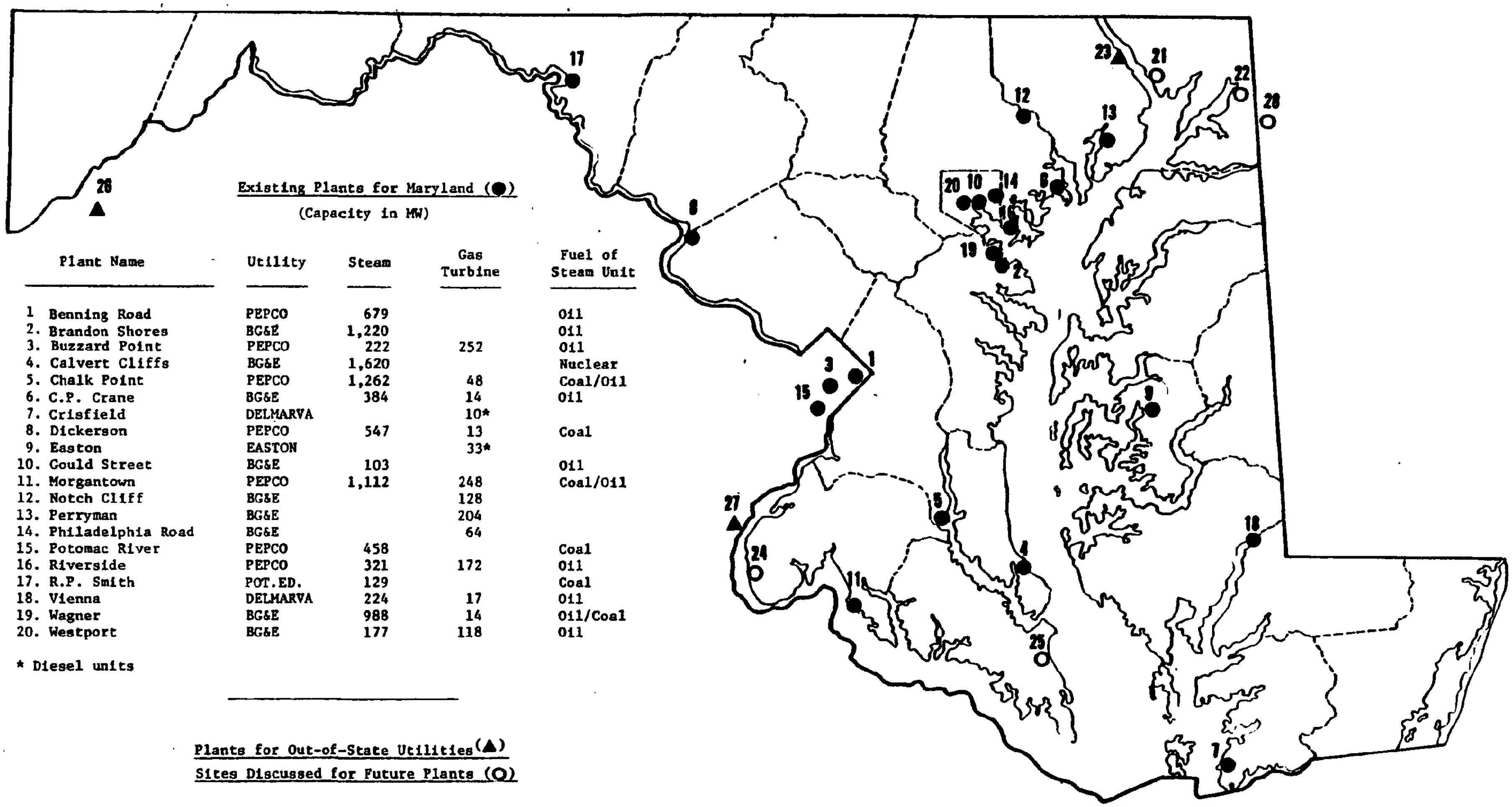
Table I-18 at the end of this Chapter contains a set of tables which present past data and future projections by both the Power Plant Siting Program and the utilities themselves for each Maryland generating utility. The tables include residential, non-residential, and total energy consumption, and peak demand for each year from 1966 to 1987, as well as annual, 5-year, and 10-year growth rates for each. Table I-18 also includes data on generating capacity, load factor, and reserve margin. Table I-1 provides data on imports and exports of power by Maryland utilities for each year from 1966 to 1977.

E. Maryland Utilities: Capacity Trends and Plans

The total generating capacity of power plants located in Maryland is 8,633.5 MW, an increase of 913.5 MW over that reported in the 1975 CEIR. In addition, 594 MW of capacity is owned by BG&E as part ownership of two Pennsylvania plants, Keystone and Conemaugh, owned principally by Philadelphia Electric. A further 1,969 MW of capacity located in the District of Columbia and Pennsylvania is owned by PEPCO, including part ownership of the Conemaugh plant.

The locations of the operating plants and proposed sites for future plants are shown in Figure I-12. The table which accompanies Figure I-12 gives the capacity and, fuel type, for each plant. Where more than one fuel type is used for a single plant, the larger component is listed first (i.e., oil/coal indicates that a mixture of oil and coal is used, but oil represents the larger amount of fuel). Table I-19 at the end of this chapter provides the capacity ratings of each of the existing and planned units of the plants owned by Maryland utilities, including the plants located outside of the State. Table I-19 also indicates the fuel type for each unit.

The data shown in Table I-19 at the end of this Chapter indicate that the newer generating units constructed in Maryland have tended to be larger than their predecessors, and they are most often designed as base-load units. The rates of growth in demand over the past ten years, and the improvement in load



Existing Plants for Maryland (●)

(Capacity in MW)

Plant Name	Utility	Steam	Gas Turbine	Fuel of Steam Unit
1 Benning Road	PEPCO	679		Oil
2. Brandon Shores	BG&E	1,220		Oil
3. Buzzard Point	PEPCO	222	252	Oil
4. Calvert Cliffs	BG&E	1,620		Nuclear
5. Chalk Point	PEPCO	1,262	48	Coal/Oil
6. C.P. Crane	BG&E	384	14	Oil
7. Crisfield	DELMARVA		10*	
8. Dickerson	PEPCO	547	13	Coal
9. Easton	EASTON		33*	
10. Gould Street	BG&E	103		Oil
11. Morgantown	PEPCO	1,112	248	Coal/Oil
12. Notch Cliff	BG&E		128	
13. Perryman	BG&E		204	
14. Philadelphia Road	BG&E		64	
15. Potomac River	PEPCO	458		Coal
16. Riverside	PEPCO	321	172	Oil
17. R.P. Smith	POT.ED.	129		Coal
18. Vienna	DELMARVA	224	17	Oil
19. Wagner	BG&E	988	14	Oil/Coal
20. Westport	BG&E	177	118	Oil

* Diesel units

Plants for Out-of-State Utilities (▲)

Sites Discussed for Future Plants (○)

21. Bainbridge
22. Chesapeake City
23. Conowingo
24. Douglas Point
25. Elms
26. Mount Storm (VEPCO)
27. Possum Point (VEPCO)
28. Summit

Figure I-12. Location of electric power plants in the Maryland region the proportion of generation coming from these units with lower operating cost. Technological improvements in generating systems have resulted in lower operating costs for larger units operated over a longer period of the duty cycle. As a result, base load units tend to be larger than other units, and they generate electricity at substantial cost savings.

Given the cost characteristics of base load plants, there are two conditions in which it is generally desirable to add base load capacity rather than cycling or peaking units. If base demand ("A" of Figure I-8) is growing rapidly enough, the most appropriate plant expansion can be a base load unit even if demand in the non-base load periods ("B" and "C" of Figure I-8) is growing more rapidly and the system load factor is declining. The precise point which determines the relative desirability of base-load versus cycling capacity is determined by factors which include the relative and absolute rates of demand growth during the three time periods (i.e., the change in the shape of the load curve), the operating costs of new units, and the operating costs of existing base load units if they were switched to cycling capacity.

Base-load capacity is also desirable when the system load factor is improving and base-period growth is occurring more rapidly, filling in the demand "valleys." Under those circumstances, the choice is most likely to be base-load. Depending on the cost reduction that results from improved technology, and assuming no differences in environmental and other impacts, it is quite possible that a system whose load factor is improving rapidly enough may be justified in adding base-load capacity even in the absence of peak load growth.

Total system energy growth in the period from 1966 to 1972 occured at an annual rate of 9.2% in Maryland, and was accompanied by a slightly higher peak load growth rate of 9.3%. The load factor improvements being forecast for the future indicate that baseload capacity additions may be appropriate in the future, although these additions are likely to be made at a slower pace than occurred in the last ten years.

The growth in consumption for the utilities operating in Maryland was accompanied by major changes in the fuel mix used in generation. Table I-13 shows the changes in generation for the four major Maryland systems from 1960 to 1977 (18).* During that period, Maryland utilities experienced a major change in the annual growth in net electric generation, which dropped from an annual rate of 11.4% for the 1960-1968 period to the 6.7% decline experienced in 1974-1975. At the same time, changing technology, fuel prices, transportation costs, and pollution control requirements led to major changes in fuel mix.

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* The four systems included in Tables I-13 to I-15 are the Allegheny Power System, Baltimore Gas and Electric Company, Delmarva Power and Light Company, and Potomac Electric Power Company. Because generating capacity is planned on a system-wide basis by these utilities, rather than for the Maryland portion of their service areas alone, the data in these tables includes the entire systems except at noted.

Table I-13. Maryland electricity generation by source, 1960-1977 (millions of kWh and percent of total)

Year	Total	Coal		Petroleum		Natural Gas		Nuclear		Hydroelectric	
	10^6 kWh	10^6 kWh	%	10^6 kWh	%	10^6 kWh	%	10^6 kWh	%	10^6 kWh	%
1960	9,316	7,792	83.6	84	0.9	7	0.1	--	--	1,433	15.4
1961	9,808	8,490	86.6	94	1.0	5	0.1	--	--	1,219	12.4
1962	11,013	9,692	88.0	98	0.9	6	0.1	--	--	1,217	11.1
1963	12,552	11,404	90.9	114	0.9	8	0.1	--	--	1,026	8.2
1964	13,991	12,681	90.6	123	0.9	5	0.1	--	--	1,182	8.4
1965	17,361	15,993	92.1	134	0.8	5	0.1	--	--	1,229	7.1
1966	18,944	17,397	91.8	131	0.7	19	0.1	--	--	1,397	7.4
1967	21,020	18,782	89.4	173	0.8	38	0.2	--	--	2,027	9.6
1968	22,054	19,614	88.9	707	3.2	45	0.2	--	--	1,688	7.7
1969	21,514	17,466	81.2	2,156	10.0	452	2.1	--	--	1,440	6.7
1970	23,594	14,942	63.3	5,844	24.8	745	3.2	--	--	2,063	8.7
1971	24,179	13,351	55.2	8,229	34.0	639	2.6	--	--	1,960	8.1
1972	27,349	11,688	42.7	12,901	47.2	478	1.7	--	--	2,282	8.3
1973	27,603	10,188	36.9	14,664	53.1	587	2.1	--	--	2,164	7.8
1974	28,821	10,001	34.7	15,989	55.4	862	3.0	--	--	1,969	6.8
1975	26,877	9,481	35.3	10,656	39.6	43	0.2	4,386	16.3	2,311	8.6
1976	31,235	12,885	41.3	9,820	31.4	21	0.1	6,426	20.6	2,088	6.7
1977	33,612	11,122	33.1	9,562	28.5	29	0.1	10,881	32.4	2,018	6.0

During the 1960-1965 period, 85-90% of Maryland electricity was produced from coal. As late as 1968 that proportion was still 89%. But by 1972, only four year later, the proportion of electricity generated from coal had been cut in half, dropping to 43% -- a reduction much larger than that experienced for utilities nationally. Coal was replaced by oil, which increased during this period from 3% to 47% as a proportion of total generation -- increasing by a factor of 15. This trend continued in Maryland through 1974. By 1975, the introduction of the first nuclear unit as Calvert Cliffs and increased prices for both foreign and domestic oil reversed the increasing share of generation coming from oil. From 1974 to 1977, that share dropped from 55% to 29%, while nuclear power increased from 0% to 32% and the proportion of generation using coal remained essentially constant.

Table I-14 shows the historic and projected capacity of the utility systems serving Maryland for the 1966-1997 time period. Over the historic portion of this period, from 1966 to 1977, capacity trends followed a pattern similar to the generation pattern shown in Table I-13. In comparing the two tables, however, the different pattern of use for the major plant types is evident. While in 1977 oil units represented 33.6% of total capacity for Maryland utilities, they provided only 28.5% of total generation. Conversely, nuclear power plants represented only 9.6% of total capacity, but accounted for 32.4% of generation. Because of operating cost characteristics, many of the existing oil units are operated on a cycling or peaking basis, while the nuclear units and most of the coal units are operated as base-load plants. The existing nuclear units tend to have the lowest operating costs of the plants owned by these systems.

Future additions to generating capacity for the four Maryland systems are shown in the upper portion of Table I-14 (19). It should be noted that plans for the 1987-1997 period do not include plant location, and are regarded by the utilities as tentative and subject to change.

The plans for the 1977-1987 time period, which includes plants under construction or in advanced planning, maintain the current capacity mix relatively unchanged. Plans for the 1987-1997 time frame, which permit a response to recent changes in fuel prices, technology and national energy and environmental policies, show a marked reduction in relative and absolute oil capacity, and a shift towards nuclear and pumped storage. As noted in the table, a review of nuclear policy by one of the Maryland utilities may lead to an increase in the proportion of coal capacity.

The lower half of Table I-14 presents similar capacity data, but does not include capacity additions in Maryland for either the APS or DP&L systems during the 1987-1997 period. Due to the multi-state nature of these systems and the tentative non-site-specific nature of the plans for this period, it is not possible to indicate likely additions to Maryland generating capacity for those systems at this time. Capacity additions by BG&E and PEPCO are assumed to be located in or adjacent to Maryland or the District of Columbia. Therefore, the additions to capacity indicated in the lower half of Table I-14 represent additions that are likely to occur within or adjacent to Maryland or the District of Columbia.

Current plans call for a 1987 capacity mix within Maryland that is little changed from the present. The small shifts that occur in the mix result

Table I-14. Generating capacity by fuel type, 1966-1997, in MW

Year	Total MW	Avg. Ann. Growth %	Coal		Petroleum		Natural Gas		Nuclear		Hydro.		Pumped Storage		Unknown	
			MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Total for Maryland Utilities (a)																
1966	8,072	8.3	7,147	88.5	177	2.2	40	0.5	--	--	708	8.8	--	--	--	--
1977	19,307	3.3	10,130	52.5	6,484	33.6	128	0.7	1,857	9.6	744	3.7	--	--	--	--
1987	26,665	4.3	14,847	55.7	7,917	30.0	128	0.5	1,940	7.3	833	3.1	1,000	3.8	--	--
1997	40,640		19,902	49.0	7,562	18.6	128	0.3	7,025 (b)	17.3	833	2.0	3,290	8.1	1,900	4.7
Total for Existing and Planned Generating Units in Maryland (c)																
1966	4,724	8.1	4,068	86.1	--	--	10	0.2	--	--	646	13.7	--	--	--	--
1977	11,076	2.2	3,923	35.4	4,759	43.0	128	0.2	1,620	14.6	646	5.8	--	--	--	--
1987	13,739	2.7	5,098	37.1	6,122	44.6	128	0.9	1,620	11.8	771	5.6	--	--	--	--
1997	17,984		6,698	37.2	5,567	31.0	128	0.7	2,920	16.2	771	4.3	1,300	7.2	600	3.3

(a) Generating capacity reported is the capacity for the full APS, BG&E, DP&L, and PEPCO systems, Easton, Deep Creek Lake, and Conowingo.

(b) The Allegheny Power System is currently reviewing projected nuclear capacity for the 1987-1997 time period. A reduction in this capacity is likely to result in an increase in coal capacity for the system.

(c) Generating capacity reported inlcudes all existing and planned units in Maryland through 1987. Only additions by BG&E and PEPCO are included in 1987-1997 additions to capacity.

from the fact that no new nuclear capacity is planned for the state during this time period and from retirement of older coal and oil units. By 1997, however, Maryland utilities anticipate that retirements of older oil units and the addition of new coal and nuclear capacity and the construction of energy storage systems (either pumped hydro or air) will alter the capacity mix. Oil capacity is expected to decline in absolute amount during that time period.

Finally, the capacity projections indicated in Table I-14 indicate that while the capacity growth rate during the second half of the forecast period is likely to be higher than during the first half, it will remain below the 8.3% annual growth experienced from 1966 to 1977. Capacity growth during the 1977 to 1987 period will remain lower than demand growth as utilities use the excess capacity that currently exists. Over the next twenty years, the projections in Table I-14 indicate that the four systems plan to add capacity that is equivalent to 25.2 Calvert Cliffs nuclear units, or 37.1 Morgantown coal units. The capacity additions within Maryland indicated in the lower half of Table I-14 are the equivalent of 8.2 Calvert Cliffs units, or 12.0 Morgantown units.

Table I-15 presents the load forecasts and planned capacity in Maryland for each Maryland utility and for the State as a whole. Capacity plans are those listed in the 1978 Ten-Year Plan (Appendix A of this report), modified by subsequent submissions to the Maryland PSC. Peak demand forecasts are taken from the report by the Department of State Planning (Appendix B of this report) and Table I-18 at the end of this chapter.

The capacity and demand data presented in the table are presented in a form that is consistent with the data shown in the Public Service Commission's Ten-Year Plan. Capacity and demand forecasts presented in that form do not provide a complete indication of the capacity available to serve Maryland demand. In the case of Potomac Edison, for example, 1978 peak demand in Maryland is projected to be 1018 MW, but 129 MW of capacity is available in Maryland. However, the entire APS system of which Potomac Edison is a part has 6679 MW of capacity available to serve a system peak of 5510 MW, which is 343 MW (or 5.4%) more than is necessary to meet peak demand plus a 15% reserve margin.

In planning for future additions to generating capacity, the planning area considered by utilities is the entire service territory of the system. Electricity produced in one part of the system is sent out over the utility's transmission and distribution lines to all points in the system. In evaluating the adequacy of the long-range plans of the utilities serving Maryland, it is necessary to evaluate the load and capacity forecasts and plans for the system as a whole.

Table I-16 presents projections of total system demand, total system capacity, and reserve margins for the years 1978 to 1987 for each of the utilities serving Maryland. Figure I-13 shows both total system peak demand plus a 15% reserve requirement and total system capacity from Table I-16. This data is taken from Table I-18.

The data in Table I-16 and Figure I-13 indicate that the current capacity plans of Maryland utilities will give the state an adequate supply of electric power over the next ten years. Based on the demand projections in the Table,

Table I-15. Peak demand and generating capacity in Maryland,(a) for Maryland utilities, 1978-1987(b)

	PE/MD (c)		BG&E (d)		DP&L/MD. (c)		PEPCO (d)		CONOWINGO (c)		TOTAL STATE (d)		
	Peak D	Capacity	D	C	D	C	D	C	D	C	D	D+15%	C(e)
1978	1,071	129	3,234	5,162	390	296	4,011	5,003	86	-0-	8,801	10,120	10,590
1979	1,135	129	3,357	5,162	412	296	4,123	4,990	90	-0-	9,117	10,485	10,577
1980	1,212	129	3,510	5,162	436	296	4,191	4,990	94	-0-	9,443	10,859	10,577
1981	1,283	129	3,676	5,162	462	296	4,242	4,990	98	-0-	9,761	11,225	10,577
1982	1,360	129	3,849	5,721	493	308	4,284	5,231	103	-0-	10,089	11,602	11,389
1983	1,443	129	4,029	5,721	523	308	4,322	5,231	107	-0-	10,424	11,988	11,389
1984	1,537	129	4,219	6,331	554	308	4,358	5,231	112	-0-	10,780	12,397	11,999
1985	1,632	129	4,418	6,456	589	308	4,393	5,631	117	-0-	11,149	12,821	12,524
1986	1,739	129	4,620	6,456	621	333	4,420	5,631	122	-0-	11,522	13,250	12,549
1987	1,854	129	4,833	6,798	652	697	4,453	5,631	128	-0-	11,920	13,708	13,255
Average Annual Growth Rate	6.3%		4.6%		5.6%		1.2%		4.5%		3.4%		

Headings: Peak Demand - D Capacity - C

(a) For Potomac Edison and Delmarva Power and Light, only the peak demand and capacity in Maryland is included.

(b) Data from Appendix B

(c) Utility forecast

(d) PPSP/DSP forecast

(e) 1987 capacity differs from value in Table I-14 mainly because Easton, Deep Creek Lake and Conowingo are not included here.

Table I-16. System peak demand and generating capacity of Maryland utilities,[a] 1978-1987

	APS (b)			BG&E (c)			DP&L/MD (b)			PEPCO (c)			CONOWINGO (b)		TOTAL STATE (c)			
	D	C	R	D	C	R	D	C	R	D	C	R	D	C	D	D+15%	C	R
1978	5,460	6,429	17.7	3,234	5,162	59.6	1,710	2,227	30.2	4,011	5,003	24.7	86	-0-	14,501	16,676	18,821	29.8
1979	5,750	7,055	22.7	3,357	5,162	53.8	1,800	2,310	28.3	4,123	4,990	21.0	90	-0-	15,120	17,388	19,517	29.1
1980	6,100	7,681	25.9	3,510	5,162	47.1	1,890	2,710	43.4	4,191	4,990	19.1	94	-0-	15,785	18,153	20,543	30.1
1981	6,395	7,681	20.1	3,676	5,162	40.4	1,890	2,709	36.8	4,242	4,990	17.6	98	-0-	16,301	18,746	20,542	26.0
1982	6,765	7,681	13.5	3,849	5,721	48.6	2,070	2,722	31.5	4,284	5,231	22.1	103	-0-	17,071	19,632	21,355	25.1
1983	7,005	8,311	18.6	4,029	5,721	42.0	2,170	2,722	25.4	4,322	5,231	21.0	107	-0-	17,633	20,278	21,985	24.7
1984	7,480	8,941	19.5	4,219	6,331	50.1	2,270	2,722	19.9	4,358	5,231	20.0	112	-0-	18,439	21,205	23,225	26.0
1985	7,870	9,571	21.6	4,418	6,456	46.1	2,370	2,821	19.0	4,393	5,631	28.2	117	-0-	19,168	22,043	24,479	27.7
1986	8,290	10,071	21.5	4,620	6,456	39.7	2,470	2,846	15.2	4,420	5,631	27.4	122	-0-	19,922	22,910	25,004	25.5
1987	8,620	10,571	22.6	4,833	6,798	40.7	2,590	3,141	21.3	4,453	5,631	26.5	128	-0-	20,624	23,718	26,141	26.8
Average Annual Growth Rate	5.2%			4.6%			4.7%			1.2%			4.5%		4.0%			

Headings: Peak Demand - D Capacity - C Reserve Margin - R

(a) Includes the complete service territories of the Allegheny Power System (including Potomac Edison) and Delmarva Power and Light. Data from Table I-18.

(b) Utility forecast

(c) PPSP/DSP forecast

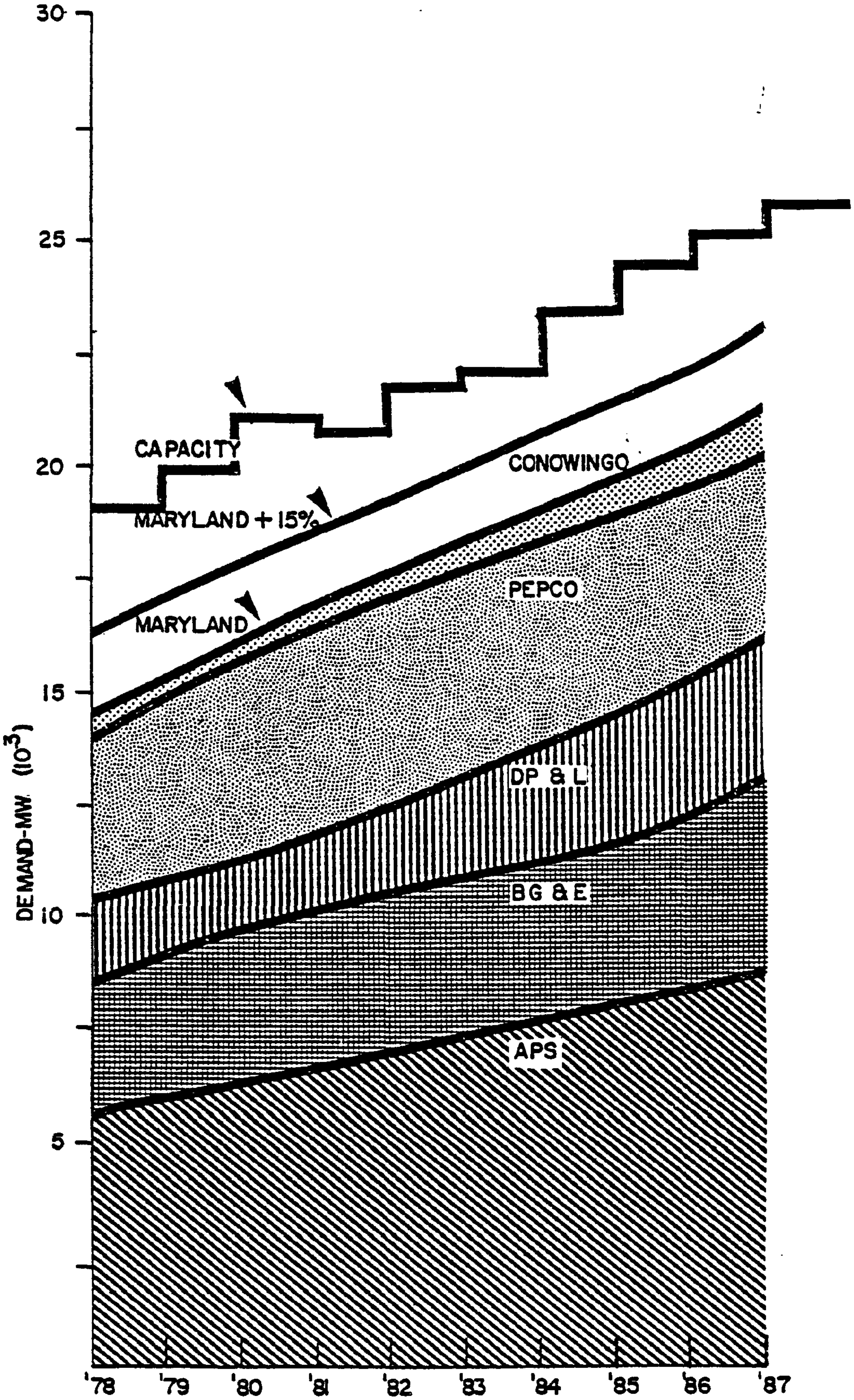

Figure I-13. Peak demand and capacity forecast for electric utility systems serving Maryland, 1977-1987 the reserve margin for all Maryland utilities taken together will range from 25% to 30% during those years. As was indicated earlier, desired reserve capacity ranges from 15% to 20%, depending on such factors as plant size and reliability and the extent of interconnection.

The state-wide average annual growth rate projected for peak demand from Table I-16 was 4.0%. An average annual growth rate of 5% over the period would result in a reserve margin of approximately 16% by 1987, indicating that even under conditions of growth in peak demand that are more rapid than anticipated, the state is likely to have adequate supplies of electricity over this time period.

Based on all available forecasts, it is expected that each of the individual utilities serving Maryland will have adequate generating capacity and reserves over the next ten years, as measured by a minimum reserve level of 15%. However, Table I-16 also shows that there is some variation in the adequacy of the electric power supply of the individual utilities.

Based on the APS forecast, the APS system is expected to fall below the 20% reserve level for a four-year period in the early 1980's. In one year, 1982, reserve capacity is expected to fall below 15%, the lowest level anticipated for any Maryland utility. Based on the PPSP forecast, the BG&E system is projected to have 40% to 50% reserve capacity through most of the period, well in excess of the 20% reserve level. (Table I-18 includes the most recent forecast prepared by BG&E, which indicates reserve levels falling in the 20% to 30% range during the 1978-1987 forecast period.) Based on the DP&L forecast, the DP&L system is expected to maintain reserves above 20% level until the mid-1980's, and above 15% throughout the entire period. The PEPCO system is anticipated to experience reserve levels which drop below 20% in 1980 and 1981, based on the PPSP forecast for that system. The forecast prepared by PEPCO projects levels falling below 20 from 1981 to 1984. Both forecasts indicate that reserves are likely to remain above 15% throughout the entire forecast period.

The adequacy of the APS system reserves depends on capacity additions planned for each of the years 1983 through 1987. APS has announced the indefinite suspension for financial reasons of the three Lower Armstrong units planned for 1983, 1984, and 1985, and the Corps of Engineers has denied a permit necessary for the construction of the Davis pumped storage units planned for 1986 and 1987. This denial is currently under litigation. In addition, a Federal Power Commission permit for Davis is under litigation in the Federal courts.

Table I-17 shows that the level of reserves for the APS without any of these units would drop below 15% in 1983, and below 0% in 1985 (20). The construction of Davis alone would not prevent reserves from dropping below 0% in this period. Without large purchases of capacity from other systems or other alternative plans, it is likely that the APS system will be unable to meet its anticipated load. Comparison of the data in Tables I-16 and I-17 shows that without the Davis and Lower Armstrong units, state-wide reserves drop below 15% by 1987, indicating that the capacity planned by other Maryland utilities may be barely adequate to meet APS requirements, assuming no other changes in the forecasts for this period. Reliance on the continuous use of

Table I-17. Effects of capacity changes on the APS system

Year	Peak Demand	Planned Capacity	Capacity Without Lower Armstrong	Reserve Margin	Capacity Without Lower Armstrong or Davis	Reserve Margin
1983	7,005	8,311	7,681	9.7	7,681	9.7
1984	7,480	8,941	7,681	2.9	7,681	2.9
1985	7,870	9,571	7,681	(-2.4)	7,681	(- 2.4)
1986	8,290	10,071	8,181	(-1.3)	7,681	(- 7.3)
1987	8,620	10,571	8,681	(0.7)	7,681	(-10.9)

large imports of power may result in reduced system reliability for all the systems involved, however. The ability of the APS system to meet projected electric power demand in the Potomac Edison service territory is currently the subject of investigation by the Maryland Public Service Commission.

The 1978 Ten Year Plan (Appendix A) lists the additions to generating capacity planned within Maryland for the next ten years. Plant additions by Maryland utility systems which are located outside of Maryland are not all included in the Ten Year Plan, but are included in Table I-18. The new units planned within Maryland have been included in the map in Figure I-12, above.

As can be seen from the plant statistics in Tables I-19 (21) and I-20 (22) and the map of Figure I-12, older plants in Maryland, as elsewhere, were located near load centers in urbanized areas. Examples can be seen in BG&E's Gould Street and Westport plants and PEPCO's Benning Road and Buzzard Point units. As was discussed in the 1975 CEIR, the introduction of high voltage transmission lines (of 230 kv or greater) has reduced the cost of siting power plants further from metropolitan areas by reducing line losses and right-of-way requirements. Suitable sites for large power plants of the scale most commonly used for baseload units are difficult to find in urban areas. The high population densities of urban areas violate Nuclear Regulatory Commission population criteria for location of nuclear plants (23), and also result in a concentration of transporation and industrial activities which cause high air pollution levels (see Chapter II). Further, the pollution control devices required by the Clean Air Act Amendments (see Chapter II) require large landfill areas for coal-burning plants. For a 1,200 MW coal unit, approximately 1,100 acres are required for waste disposal over the operating life of the plant. Tracts of this size are rarely available in urban areas, necessitating off-site disposal for such wastes.

All of these trends and constraints favor the siting of large base load and cycling power plants in non-urban areas. The 1975 CEIR depicted the shift away from urban siting. Of the plants and sites included in the current Ten Year Plan, only Brandon Shores is within 20 miles of a metropolitan area. The sites currently listed in the Ten Year Plan follow the trend of siting outside of metropolitan areas.

The 1978 Ten Year Plan lists new units planned at seven sites in Maryland, as well as six sites at which no units are currently planned. These Maryland sites are described briefly, by utility, in Table I-20.

Table I-18. Projected and actual energy demand, capability and growth rates for Maryland utilities. 1966 through 1987

Table I-18a. Allegheny Power System (total system)[a]

Year and Growth Rates[b]	Energy Sales (MWh)[c] Residential	Non-Residential	Total	Peak Load (MW)[c] Summer	Winter	Capacity (MW)[c]	Reserve Margin (%)	Load Factor
1966	3,711,236	11,000,930	14,712,166	2,425	2,661	2,343	- 12.0	68.9
1					7.13			
5								
10								
1967	4,027,051	11,279,560	15,306,611	2,453	2,863	2,646	- 5.8	67.7
1	8.51	2.53	4.04	1.15	7.59			
5								
10								
1968	4,409,112	12,253,335	16,662,447	2,749	3,017	3,222	6.8	68.8
1	9.49	8.63	8.86	12.07	5.38			
5								
10								
1969	4,845,511	13,357,748	18,203,259	2,941	3,343	3,809	14.0	67.7
1	9.90	9.01	9.25	6.98	10.81			
5								
10								
1970	5,318,888	14,800,349	20,119,237	3,206	3,785	4,293	17.6	68.0
1	9.77	10.80	10.53	9.01	13.22			
5								
10								
1971	5,694,162	15,584,594	21,278,756	3,327	3,769	4,819	27.3	69.3
1	7.08	5.30	5.76	3.77	- 0.42			
5	8.94	7.21	7.66	6.53	7.21			
10								
1972	6,136,732	16,678,103	22,814,835	3,622	4,039	5,503	37.2	69.9
1	7.77	7.02	7.22	8.87	7.16			
5	8.79	8.14	8.30	8.11	7.12			
10								
1973	6,614,299	18,057,714	24,672,013	4,040	4,230	5,965	41.0	71.6
1	7.78	8.27	8.14	11.54	4.73			
5	8.45	8.06	8.17	8.00	6.99			
10								
1974	6,808,969	18,134,728	24,943,697	3,916	4,272	6,663	57.6	73.6
1	2.94	0.43	1.10	- 3.07	0.99			
5	7.04	6.31	6.50	5.89	5.03			
10								
1975	7,228,634	16,732,955	23,961,589	3,959	4,650	6,429	40.1	64.8
1	6:16	- 7.73	- 3.94	1.10	8.85			
5	6.33	2.48	3.56	4.31	4.20			
10					6.47			
1976	7,523,518	19,180,935	26,704,453	4,284	5,031	6,429	28.8	66.1
1	4.08	14.63	11.45	8.21	8.19			
5	5.73	4.24	4.65	5.19	5.95			
10	7.32	5.72	6.14	5.86	6.58			
1977	8,095,776	20,151,533	28,247,309	4,539	5,174	6,429	24.3	68.7
1	7.61	5.06	5.78	5.95	2.84			
5	5.67	3.86	4.36	4.62	5.08			
10	7.23	5.97	6.32	6.35	6.10			
1978	8,521,000	20,340,236	28,861,236	4,720	5,460	6,429	17.7	66.6
1	5.25	0.94	2.17	3.99	5.53			
5	5.20	2.41	3.19	3.16	5.24			
10	6.81	5.20	5.65	5.55	6.11			
1979	9,007,000	21,735,500	30,742,500	4,870	5,750	7,055	22.7	66.7
1	5.70	6.86	6.52	3.18	5.31			
5	5.75	3.69	4.27	4.46	6.12			
10	6.40	4.99	5.38	5.17	5.57			

Table I-18a. Allegheny Power System (Continued)

Year and Growth Rates (b)	Energy Sales (MWh) (c)			Peak Load (MW) (c)		Capacity (MW) (c)	Reserve Margin (%)	Load Factor
	Residential	Non-Residential	Total	Summer	Winter			
1980	9,529,000	22,807,200	32,336,200	5,170	6,100	7,681	25.9	65.5
1	5.80	4.93	5.18	6.16	6.09			
5	5.68	6.39	6.18	5.43	5.58			
10	6.00	4.42	4.86	4.89	4.89			
1981	10,086,000	23,716,000	33,802,000	5,390	6,395	7,681	20.1	65.3
1	5.85	3.98	4.53	4.26	4.84			
5	6.04	4,34	4.83	4.70	4.91			
10	5.88	4.29	4.74	4.94	5.43			
1982	10,634,000	25,048,500	35,682,500	5,625	6,765	7,681	13.5	65.8
1	5.43	5.62	5.56	4.36	5.79			
5	5.61	4.45	4.78	4.38	5.51			
10	5.65	4.15	4.57	4.50	5.29			
1983	11,234,000	26,027,200	37,261,200	5,875	7,005	8,311[a]	18.6	65.6
1	5.64	3.91	4.42	4.44	3.55			
5	5.68	5.05	5.24	4.48	5.11			
10	5.44	3.72	4.21	3.82	5.17			
1984	11,833,000	27,202,800	39,035,800	6,205	7,480	8,941[a]	19.5	64.6
1	5.33	4.52	4.76	5.62	6.78			
5	5.61	4.59	4.89	4.96	5.40			
10	5.68	4.14	4.58	4.71	5.76			
1985	12,485,000	28,501,400	40,986,400	6,560	7,870	9,571[a]	21.6	64.6
1	5.51	4.77	5.00	5.72	5.21			
5	5.55	4.56	4.86	4.88	5.23			
10	5.62	5.47	5.51	5.18	5.40			
1986	13,143,000	29,732,000	42,875,000	6,850	8,290	10,071[c]	21.5	64.2
1	5.27	4.32	4.61	4.42	5.34			
5	5.44	4.63	4.87	4.91	5.33			
10	5.74	4.48	4.85	4.81	5.12			
1987	13,849,000	30,900,600	44,749,600	7,130	8,620	10,571[c]	22.6	64.0
1	5.37	3.93	4.37	4.09	3.98			
5	5.43	4.29	4.63	4.86	4.97			
10	5.52	4.37	4.71	4.62	5.24			

(a) Data represents the entire APS system, including Potomac Edison, West Penn Power Co., Monongahela Power Co.

(b) 1 yr growth, percent
5 yr avg. growth, percent
10 yr avg. growth, percent

(c) Forecast prepared by APS

Table I-18b. Potomac Edison Company (Maryland Portion)*

Year and Growth Rates (b)	Energy Sales (MWh) (c) Residential	Non-Residential	Total	Peak Load (MW) (c) Summer	Winter	Capacity (MW) (c)	Reserve Margin (%) (d)	Load Factor (d)
1966	488,702	931,649	1,420,351		336	129		
1								
5								
10								
1967	539,658	1,014,555	1,554,213		362	129		
1	10.43	8.90	9.42		7.74			
5								
10								
1968	599,608	1,114,952	1,714,560		390	129		
1	11.11	9.90	10.32		7.73			
5								
10								
1969	664,953	1,221,389	1,886,342		420	129		
1	10.90	9.55	10.02		7.69			
5								
10								
1970	730,579	1,894,813	2,625,392		550	129		
1	9.87	55.14	39.18		30.95			
5								
10								
1971	787,501	2,504,470	3,301,971		601	129		
1	7.79	32.18	25.77		9.27			
5	10.01	21.87	18.38		12.33			
10								
1972	850,904	2,624,932	3,475,836		656	129		
1	8.05	4.81	5.27		9.15			
5	9.53	20.94	17.47		12.63			
10								
1973	929,917	2,784,849	3,714,766		682	129		
1	9.29	6.09	6.87		3.96			
5	9.17	20.09	16.72		11.83			
10								
1974	985,282	2,725,246	3,710,528		693	129		
1	5.95	- 2.14	- 0.12		1.61			
5	8.18	17.41	14.49		10.53			
10								
1975	1,065,026	2,629,187	3,694,213		802	129		
1	8.09	- 3.52	- 0.44		15.73			
5	7.83	6.77	7.07		7.84			
10								
1976	1,142,266	3,911,928	5,054,194		916	129		
1	7.25	48.79	36.81		14.21			
5	7.72	11.90	8.89		8.79			
10	8.86	15.43	13.53		10.55			
1977	1,234,939	4,118,514	5,353,453		1,018	129		
1	8.11	5.28	5.92		2.13			
5	7.73	9.43	9.02		9.19			
10	8.63	15.04	13.17		10.89			
1978			5,632,368		1,071	129		
1			5.21		5.21			
5			8.68		9.45			
10			12.63		10.63			
1979			5,969,184		1,135	129		
1			5.98		5.98			
5			9.98		10.37			
10			12.21		10.45			

Table I-18b. Potomac Edison Company (Maryland Portion) (Continued)

Year and Growth Rates(b)	Energy Sales (MWh)(c)			Peak Load (MW)(c)		Capacity (MW)(c)	Reserve Margin (%)(d)	Load Factor(d)
	Residential	Non-Residential	Total	Summer	Winter			
1980			6,373,894		1,212	129		
1			6.78		6.78			
5			11.53		8.61			
10			9.28		8.22			
1981			6,747,404		1,283	129		
1			5.86		5.86			
5			5.95		6.97			
10			7.41		7.88			
1982			7,152,248		1,360	129		
1			6.00		6.00			
5			5.96		5.96			
10			7.48		7.56			
1983			7,588,536		1,443	129		
1			6.10		6.10			
5			6.14		6.14			
10			7.40		7.78			
1984			8,082,549		1,537	129		
1			6.51		6.51			
5			6.25		6.25			
10			8.10		8.29			
1985			8,582,051		1,632	129		
1			6.18		6.18			
5			6.13		6.13			
10			8.79		7.36			
1986			9,145,033		1,739	129		
1			6.56		6.56			
5			6.27		6.27			
10			6.11		6.62			
1987			9,749,520		1,854	129		
1			6.61		6.61			
5			6.39		6.39			
10			6.18		6.18			

(a) Data represents only the Maryland portion of the Potomac Edison Service territory

(b) 1 yr growth, percent
5 yr avg. growth, percent
10 yr avg. growth, percent

(c) Forecast prepared by Allegheny Power System

(d) Not calculated separately for Maryland portion of system

Table I-18c. Baltimore Gas and Electric Company

Year and Growth Rates (a)	Energy Sales (MWh) (b) Residential	Non-Residential	Total	Peak Load (MW) (b) Summer	Winter	Capacity (MW) (c)	Reserve Margin (%)	Load Factor	BG&E Forecast (c) Summer Peak	Reserve Margin
1966	2,347,000	6,306,000	8,653,000	1,817	1,422	1,866	2.7	58.9		
1										
5										
10										
1967	2,548,461	6,797,355	9,345,816	1,927	1,558	2,095	8.7	59.8		
1	8.58	7.79	8.01	6.05	9.56					
5										
10										
1968	2,933,422	7,238,078	10,171,500	2,179	1,683	1,898	- 12.9	57.7		
1	15.11	6.48	8.83	13.08	8.02					
5										
10										
1969	3,285,000	7,880,000	11,165,000	2,306	1,792	2,046	- 11.3	59.7		
1	11.99	8.87	9.77	5.83	6.48					
5										
10										
1970	3,664,564	8,306,165	11,970,729	2,496	1,954	2,290	- 8.3	59.0		
1	11.55	5.41	7.22	8.24	9.04					
5										
10										
1971	3,864,160	8,620,399	12,484,559	2,605	2,053	2,290	- 12.1	58.7		
1	5.45	3.78	4.29	4.37	5.07					
5	10.49	6.25	7.61	7.47	7.62					
10										
1972	4,102,000	8,889,000	12,991,000	2,960	2,006	2,917	- 1.5	53.9		
1	6.16	3.12	4.06	13.63	- 2.29					
5	9.99	5.51	6.81	8.96	5.18					
10										
1973	4,617,840	9,722,929	14,340,819	3,334	2,302	3,491	4.7	52.7		
1	12.58	9.38	10.39	12.64	14.76					
5	9.50	6.08	7.11	8.88	6.46					
10										
1974	4,469,140	9,520,845	13,989,985	3,190	2,177	3,294	3.2	53.9		
1	(- 3.22)	(- 2.08)	(- 2.45)	- 4.32	- 5.43					
5	6.35	3.86	4.61	6.71	3.97					
10										
1975	4,664,000	9,194,000	13,858,000	3,256	2,301	4,402	35.2	52.4		
1	4.36	- 3.43	- 0.94	2.07	5.10					
5	4.94	2.05	2.97	5.46	3.32					
10										
1976	4,887,793	9,870,413	14,758,206	3,234	2,418	4,408	36.3	56.2		
1	4.80	7.36	6.50	- 0.68	5.08					
5	4.81	2.12	3.40	4.42	3.33					
10	7.61	4.58	5.48	5.93	5.45					
1977	5,231,000	10,231,000	15,462,000	3,588	2,640	5,162	43.9	52.7		
1	7.02	3.65	4.77	10.95	9.18					
5	4.98	2.85	3.54	3.92	5.65					
10	7.46	4.17	5.16	6.41	5.42					
1978	5,070,266	10,912,507	15,982,773	3,234	2,770	5,162	59.6		3,740	38.0
1	(- 3.07)	6.66	3.37	(- 9.87)	4.92				4.24	
5	1.89	2.34	2.19	(- 0.61)	3.77				2.32	
10	5.62	4.19	4.62	4.03	5.11				5.55	
1979	5,292,654	11,282,637	16,575,291	3,357	2,900	5,162	53.8		3,930	31.3
1	4.39	3.39	3.71	3.80	4.69				5.08	
5	3.44	3.45	3.45	1.03	5.90				4.26	
10	4.89	3.65	4.03	3.83	4.93				5.48	

Table I-18c. Baltimore Gas and Electric Company (Continued)

Year and Growth Rates(a)	Energy Sales (MWh) (b)			Peak Load (MW) (b)		Capacity (MW) (c)	Reserve Margin (%)	Load Factor	BG&E Forecast (c)	
	Residential	Non-Residential	Total	Summer	Winter				Summer Peak	Reserve Margin
1980	5,553,091	11,993,630	17,546,721	3,510	3,046	5,162	47.1		4,110	25.6
1	4.92	6.30	5.86	4.56	5.03				4.58	
5	3.55	5.46	4.83	1.93	5.77				4.77	
10	4.24	3.74	3.90	3.47	4.54				5.11	
1981	5,823,603	12,719,192	18,542,795	3,676	3,190	5,162	40.4		4,310	19.8
1	4.87	6.05	5.68	4.73	4.73				4.87	
5	3.57	5.20	4.67	2.60	5.70				5.91	
10	4.19	3.97	4.04	3.50	4.51				5.16	
1982	6,121,884	13,464,105	19,585,989	3,849	3,342	5,721	48.6		4,520	26.6
1	5.12	5.86	5.63	4.71	4.76				4.87	
5	3.20	5.65	4.84	1.41	4.83				4.73	
10	4.09	4.24	4.19	2.66	5.24				4.32	
1983	6,446,135	14,234,493	20,680,628	4,029	3,505	5,721	42.0		4,730	21.0
1	5.30	5.72	5.59	4.68	4.88				4.65	
5	4.92	5.46	5.29	4.49	4.82				4.81	
10	3.39	3.89	3.73	1.91	4.29				3.56	
1984	6,796,829	15,036,050	21,832,879	4,219	3,675	6,331	50.1		4,940	28.2
1	5.44	5.63	5.57	4.72	4.85				4.44	
5	5.13	5.91	5.66	4.68	4.85				4.68	
10	4.28	4.68	4.55	2.84	5.38				4.47	
1985	7,174,723	15,874,458	23,049,181	4,418	3,855	6,456	46.1		5,160	25.1
1	5.56	5.58	5.57	4.72	4.90				4.45	
5	5.26	5.77	5.61	4.71	4.82				4.66	
10	4.40	5.16	5.22	3.10	5.30				4.71	
1986	7,576,536	16,713,496	24,290,026	4,620	4,042	6,456	39.7		5,390	19.8
1	5.60	5.29	5.38	4.57	4.85				4.46	
5	5.40	5.61	5.55	4.68	4.85				4.57	
10	4.48	5.41	5.11	3.63	5.27				5.24	
1987	8,007,837	17,596,305	25,604,142	4,833	4,239	6,798	40.7		5,630	20.7
1	5.69	5.28	5.41	4.61	4.87				4.45	
5	5.52	5.50	5.50	4.66	4.87				4.49	
10	4.35	5.57	5.17	3.02	4.85				4.61	

(a) 1 yr growth, percent
5 yr avg. growth, percent
10 yr avg. growth, percent

(b) Forecast prepared by PPSP

(c) Forecast prepared by BG&E

Table I-18d. Delmarva Power and Light Company (total system)[a]

Year and Growth Rates[b]	Energy Sales (MWh)[c] Residential	Energy Sales (MWh)[c] Non-Residential[d]	Energy Sales (MWh)[c] Total	Peak Load (MW)[c] Summer	Peak Load (MW)[c] Winter	Capacity (MW)[c]	Reserve Margin (%)	Load Factor
1966	838,548	2,636,665	3,475,213	710	617	799	12.5	62.8
1								
5								
10								
1967	910,547	2,855,780	3,766,327	748	680	836	11.8	64.7
1	8.59	8.31	8.38	5.28	10.18			
5								
10								
1968	1,037,222	3,409,021	4,446,243	898	751	864	- 3.8	63.1
1	13.91	19.37	18.05	20.12	10.54			
5								
10								
1969	1,108,945	3,743,009	4,851,954	955	859	853	- 10.6	65.0
1	6.91	9.80	9.12	6.30	14.33			
5								
10								
1970	1,280,420	3,897,514	5,177,934	1,045	947	1,045	0.0	63.7
1	15.46	4.13	6.72	9.47	10.33			
5								
10								
1971	1,380,763	4,093,144	5,473,907	1,135	986	1,210	6.6	62.0
1	7.84	5.02	5.72	8.61	4.08			
5	10.49	9.19	9.51	9.83	9.84			
10								
1972	1,463,821	4,457,292	5,921,113	1,259	1,043	1,237	- 1.7	61.0
1	6.02	8.90	8.17	10.94	5.76			
5	9.96	9.31	9.47	10.99	8.95			
10								
1973	1,629,640	4,771,818	6,401,458	1,508	1,201	1,406	- 6.8	55.1
1	11.33	7.06	8.11	19.76	15.14			
5	9.46	6.96	7.56	10.92	9.84			
10								
1974	1,597,471	4,641,354	6,238,825	1,447	1,144	1,801	24.5	55.8
1	- 1.97	- 2.73	- 2.54	- 4.03	- 4.73			
5	7.57	4.40	5.16	8.68	5.91			
10								
1975	1,672,180	4,345,147	6,017,327	1,463	1,187	1,959	33.8	53.8
1	5.48	- 6.38	- 3.55	- 1.11	3.73			
5	2.71	2.20	3.05	6.96	4.61			
10								
1976	1,787,663	4,473,186	6,260,849	1,434	1,276	1,971	37.4	57.3
1	6.91	2.95	4.05	- 1.98	7.51			
5	5.30	1.79	2.72	4.79	4.11			
10	7.86	5.43	6.06	7.28	7.54			
1977	1,924,723	4,612,038	6,536,761	1,609	1,402	2,052	27.5	52.8
1	7.67	3.10	4.41	12.21	9.88			
5	5.63	0.68	2.00	5.03	6.09			
10	7.77	4.91	5.69	7.97	7.51			
1978	1,949,612	4,843,885	6,793,497	1,710	N/A	2,227	30.2	N/A
1	1.29	5.03	3.93	6.26				
5	3.65	0.30	1.20	2.55				
10	6.51	3.58	4.33	6.65				
1979	2,099,950	5,181,002	7,280,952	1,800	N/A	2,310	28.3	N/A
1	7.71	6.96	7.18	5.26				
5	5.62	7.22	3.14	4.46				
10	6.59	3.30	4.14	6.55				

Table I-18d. Delmarva Power and Light Company (total system) (Continued)

Year and Growth Rates(b)	Energy Sales (MWh)(c) Residential	Non-(d) Residential	Total	Peak Load (MW)(c) Summer	Winter	Capacity (MW)(c)	Reserve Margin (%)	Load Factor
1980	2,249,924	5,393,335	7,643,259	1,890	N/A	2,710	43.4	N/A
1	7.14	4.10	4.98	5.00				
5	6.12	4.42	4.90	5.25				
10	5.80		3.97	6.11				
1981	2,380,702	5,876,192	8,384,075	1,980	N/A	2,709	36.8	N/A
1	11.47	8.95	9.69	4.76				
5	5.90	5.61	6.01	6.66				
10	5.60	3.30	4.36	5.72				
1982	2,507,883	5,925,941	8,433,824	2,070	N/A	2,722	31.5	N/A
1	5.34	0.85	0.59	4.55				
5	5.44	5.14	5.23	5.16				
10	5.53	2.89	3.60	5.10				
1983	2,637,650	6,192,999	8,830,649	2,170	N/A	2,722	25.4	N/A
1	5.17	4.51	4.71	4.83				
5	6.23	5.04	5.39	4.88				
10	4.93	2.64	3.27	3.71				
1984	2,775,979	6,430,890	9,206,869	2,270	N/A	2,722	19.9	N/A
1	5.24	3.84	4.26	4.61				
5	5.74	4.42	4.81	4.75				
10	5.68	3.31	3.97	4.61				
1985	2,906,426	6,705,276	9,611,752	2,370	N/A	2,821	19.0	N/A
1	4.70	0.84	4.40	4.41				
5	5.25	4.45	3.98	4.63				
10	5.68	4.43	4.79	4.94				
1986	3,046,865	7,035,350	10,082,215	2,470	N/A	2,846	15.2	N/A
1	4.83	4.92	4.89	4.22				
5	5.06	3.67	3.76	4.52				
10	5.48	4.63	4.88	5.59				
1987	3,194,811	7,405.925	10,600,736	2,590	N/A	3,141	21.3	N/A
1	4.86	5.27	5.14	4.86				
5	4.96	4.56	4.68	4.58				
10	5.20	4.85	4.95	4.87				

(a) Excludes energy sales to Dover and Easton; includes only the portion of Dover and Easton peak demand provided by DP&L

(b) 1 yr growth, percent
5 yr avg. growth, percent
10 yr avg. growth, percent

(c) Forecast prepared by DP&L

(d) Excludes sales for resale in Maryland

Table I-18e. Delmarva Power and Light Company of Maryland[a]

Year and Growth Rates (b)	Energy Sales (MWh) (c)			Peak Load (MW) (c)		Capacity (MW) (c)	Reserve Margin (%) (d)	Load Factor (d)
	Residential	Non-Residential	Total	Summer	Winter			
1966	198,797	299,477	498,274	141	116	105		
1								
5								
10								
1967	220,454	327,383	547,837	149	139	105		
1	10.89	9.32	9.95	5.67	19.83			
5								
10								
1968	253,058	367,772	620,830	177	155	132		
1	14.79	12.34	13.32	18.79	11.51			
5								
10								
1969	288,757	410,236	698,493	197	164	132		
1	14.11	11.55	12.59	11.30	5.81			
5								
10								
1970	321,865	451,257	773,122	210	206	132		
1	14.47	10.00	10.61	6.60	25.61			
5								
10								
1971	354,861	480,329	835,190	227	227	282		
1	10.25	6.44	8.03	8.10	10.19			
5	12.29	9.91	10.88	9.99	14.37			
10								
1972	389,453	510,769	900,222	278	233	282		
1	9.75	6.34	7.79	22.47	2.64			
5	12.05	9.30	10.44	13.28	10.88			
10								
1973	441,381	563,605	1,004,986	327	290	252		
1	13.33	10.34	11.64	17.63	24.46			
5	11.77	8.91	10.11	13.06	13.35			
10								
1974	457,947	569,227	1,027,174	319	275	252		
1	3.75	1.00	2.21	-2.45	-5.17			
5	9.66	6.77	8.01	10.12	10.89			
10								
1975	483,370	593,163	1,076,533	342	294	252		
1	5.55	4.21	4.81	7.21	6.91			
5	8.47	5.62	6.85	10.25	7.37			
10								
1976	542,509	647,974	1,190,483	315	347	252		
1	12.23	9.24	10.58	-7.89	18.03			
5	6.85	6.17	7.35	6.77	8.86			
10	10.56	8.02	9.10	8.37	11.58			
1977	623,778	733,443	1,357,221	384	400	252		
1	14.98	13.19	14.01	21.90	15.27			
5	9.88	7.50	8.56	6.67	11.41			
10	10.96	8.40	9.50	9.93	11.15			
1978	655,911	787,717	1,443,630	390	N/A	252		
1	5.15	7.40	6.37	1.56				
5	8.24	6.92	7.51	3.59				
10	9.99	7.91	8.80	8.22				
1979	704,979	863,973	1,568,955	412	N/A	252		
1	7.48	9.68	8.68	5.64				
5	9.01	8.70	8.84	5.25				
10	9.34	7.73	8.43	7.66				

Table I-18e. Delmarva Power and Light Company of Maryland (Continued)

Year and Growth Rates(b)	Energy Sales (MWh) (c)			Peak Load (MW)(c)		Capacity (MW) (c)	Reserve Margin (%) (d)	Load Factor (d)
	Residential	Non-Residential	Total	Summer	Winter			
1980	749,888	921,654	1,671,545	436	N/A	252		
1	6.37	6.67	6.54	5.83				
5	9.18	9.21	9.20	4.98				
10	8.83	7.40	8.02	7.58				
1981	800,740	978,465	1,779,211	462	N/A	252		
1	6.78	6.16	6.44	5.96				
5	8.10	8.59	8.37	7.96				
10	8.48	7.37	7.86	7.36				
1982	853,336	1,045,251	1,898,589	493	N/A	252		
1	6.57	6.83	6.71	6.71				
5	6.47	7.34	6.94	5.12				
10	8.16	7.42	7.75	5.90				
1983	905,688	1,114,185	2,019,876	523	N/A	252		
1	6.13	6.59	6.39	6.09				
5	6.67	7.18	6.95	6.04				
10	7.45	7.05	7.23	4.81				
1984	960,747	1,168,717	2,129,465	554	N/A	252		
1	6.08	4.89	5.43	5.93				
5	6.39	6.23	6.30	6.10				
10	7.69	7.46	7.56	5.67				
1985	1,014,699	1,241,103	2,255,805	589	N/A	252		
1	5.62	6.19	5.93	6.32				
5	6.24	6.13	6.18	6.20				
10	7.70	7.66	7.68	5.59				
1986	1,072,143	1,323,171	2,395,316	621	N/A	252		
1	5.66	6.61	6.18	5.43				
5	6.01	6.22	6.13	6.09				
10	7.05	7.40	7.24	7.02				
1987	1,129,042	1,405,751	2,534,794	652	N/A	618		
1	5.31	6.24	5.82	4.99				
5	5.76	6.11	5.95	5.75				
10	6.11	6.72	6.45	5.44				

(a) Data represents the Maryland portion of the DP&L system; data excludes sales to Easton; data includes only the portion of the Easton peak provided by DP&L

(b) 1 yr growth, percent
5 yr avg. growth, percent
10 yr avg. growth, percent

(c) Forecast prepared by DP&L, Easton not inlcuded in plant capacity.

(d) Not calculated separately for Maryland portion of system.

Table I-18f. Potomac Electric Power Company (total system)[a]

Year and Growth Rates (b)	Energy Sales (MWh)(c) Residential	Non-Residential	Total	Peak Load (MW)(c) Summer	Winter	Capacity (MW)(d)	Reserve Margin (%)	Load Factor	PEPCO Forecast(d) Summer Peak	Reserve Margin
1966	1,978,031	5,660,581	7,638,612	2,123	1,249	2,363	11.3	N/A		
1										
5										
10										
1967	2,084,517	6,194,069	8,278,586	2,283	1,385	2,395	4.9	N/A		
1	5.38	9.42	8.38	7.54	10.89					
5										
10										
1968	2,401,544	6,915,402	9,316,946	2,627	1,520	2,973	13.2	N/A		
1	15.21	11.65	12.54	15.07	9.75					
5										
10										
1969	2,648,658	7,605,966	10,254,624	2,759	1,622	2,973	7.8	N/A		
1	10.29	9.98	10.06	5.02	6.71					
5										
10										
1970	2,931,982	8,251,123	11,183,105	2,908	1,813	3,708	27.5	N/A		
1	10.70	8.48	9.05	5.40	11.78					
5										
10										
1971	3,037,526	8,696,058	11,733,584	3,045	1,919	4,259	39.9	N/A		
1	3.60	5.39	4.92	4.71	5.85					
5	8.96	8.97	8.96	7.48	8.97					
10										
1972	3,121,794	9,068,504	12,190,298	3,479	1,990	4,454	28.0	N/A		
1	2.77	4.28	3.89	14.25	3.70					
5	8.41	7.92	8.05	8.79	7.52					
10										
1973	3,529,039	9,704,095	13,233,134	3,680	2,159	4,721	28.3	N/A		
1	13.05	7.01	8.55	5.78	8.49					
5	2.48	7.01	7.27	6.97	7.27					
10										
1974	3,304,222	8,884,725	12,188,947	3,502	2,012	4,933	40.9	N/A		
1	- 6.37	- 8.44	- 7.89	- 4.84	- 6.81					
5	4.52	3.16	3.52	4.88	4.40					
10										
1975	3,399,452	9,322,077	12,721,529	3,623	2,145	5,190	43.3	N/A		
1	2.88	4.92	4.37	3.46	6.61					
5	3.00	2.47	2.61	4.49	3.42					
10										
1976	3,484,531	4,603,245	13,087,776	3,500	2,334	5,010	43.1	N/A		
1	2.50	3.02	2.88	- 3.39	8.81					
5	2.78	2.00	2.21	2.82	3.99					
10	6.38	5.43	5.53	5.13	6.45					
1977	3,617,267	10,029,546	13,646,813	3,857	2,508	5,013	30.0	N/A		
1	3.81	4.44	4.27	10.20	7.46					
5	2.99	2.03	2.28	2.82	4.74					
10	5.67	4.94	5.13	5.38	6.12					
1978	3,761,400	10,472,600	14,234,000	4,011		5,003	24.7	N/A	3,922	27.6
1	3.98	4.42	4.30	3.99					1.69	
5	1.28	1.54	1.47	1.74					1.28	
10	4.59	4.24	4.33	4.32					4.09	
1979	3,907,300	10,821,300	14,728,600	4,123		4,990	21.0	N/A	4,007	24.5
1	3.88	3.33	3.47	2.79					2.17	
5	3.41	4.02	3.86	3.32					14.77	
10	3.96	3.59	3.69	4.10					3.80	

Table I-18f. Potomac Electric Power Company (total system) (Continued)

Year and Growth Rates (b)	Energy Sales (MWh) (c)			Peak Load (MW) (c)		Capacity (MW) (d)	Reserve Margin (%)	Load Factor	PEPCO Forecast (d)	
	Residential	Non-Residential	Total	Summer	Winter				Summer Peak	Reserve Margin
1980	4,058,700	11,076,400	15,135,100	4,191		4,990	19.1	N/A	4,098	21.8
1	3.87	2.36	2.76	1.65					2.27	
5	3.61	3.51	3.54	2.96					13.82	
10	3.31	2.99	3.07	3.72					3.49	
1981	4,231,600	11,276,200	15,507,800	4,242		4,990	17.6	N/A	4,220	18.2
1	4.26	1.80	2.46	1.22					2.97	
5	3.96	3.26	3.45	3.92					12.58	
10	3.37	2.63	2.83	3.37					3.32	
1982	4,404,100	11,423,700	15,827,800	4,284		5,231	22.1	N/A	4,350	20.3
1	4.08	1.31	2.06	0.99					3.08	
5	4.01	2.64	3.01	2.12					2.43	
10	3.50	2.34	2.65	2.10					2.26	
1983	4,590,300	11,571,800	16,162,100	4,322		5,231	21.0	N/A	4,484	16.7
1	4.23	1.30	2.11	0.89					3.08	
5	4.06	2.02	2.57	1.50					2.71	
10	2.66	1.76	2.02	1.62					2.00	
1984	4,790,300	11,703,800	16,494,100	4,358		5,231	20.0	N/A	4,563	14.6
1	4.36	1.14	2.05	0.83					1.76	
5	4.16	1.58	2.29	1.11					2.63	
10	3.78	2.79	3.07	2.29					2.68	
1985	4,999,700	11,824,000	16,823,700	4,393		5,631	28.2	N/A	4,638	21.4
1	4.37	1.03	2.00	0.80					1.64	
5	4.26	1.31	2.14	0.95					2.51	
10	3.93	2.41	2.83	1.95					2.50	
1986	5,234,900	11,853,400	17,088,300	4,420		5,631	27.4	N/A	4,712	19.5
1	4.70	2.49	1.57	0.61					1.60	
5	4.35	1.00	1.96	0.83					2.23	
10	4.15	2.13	2.70	2.36					3.02	
1987	5,484,400	11,961,700	17,446,100	4,453		5,631	26.5	N/A	4,787	17.6
1	4.77	0.91	2.09	0.75					1.59	
5	4.49	0.93	1.97	0.78					1.93	
10	4.25	1.78	2.49	1.45					2.18	

(a) Data includes the entire PEPCO system; data excludes energy sales to SMECO; data includes SMECO peak

(b) 1 yr growth, percent
 5 yr avg. growth, percent
 10 yr avg. growth, percent

(c) Forecast prepared by PPSP

(d) Forecast prepared by PEPCO

Table I-19. Generating capability and fuel type by generating unit for Maryland utilities

For all utilities:

1. GT units are gas turbines; IC units are diesels; all other units are steam.

2. Changes in net capability include additions, retirements and deratings.

3. Station total is given as capability at peak season (Tables A and B, Winter; Tables C and D, Summer)

4. For stations with joint ownership capability listed in the tables is the utility's share of total station capability. The total capability of jointly owned units is as follows:

		Summer	Winter
Conemaugh	1	850	850
	2	850	850
	IC 1	11	11
Dickerson	4	800	800
Keystone	1	840	850
	2	840	850
	IC 3-6	11	11
Peach Bottom	2	1,051	1,055
	3	1,035	1,035
Safe Harbor		228	228
Existing Expansion		188	188
Salem	1	1,090	1,090
	2	1,115	1,115
	GT 3	38	48

Table I-19a. Allegheny power system (the Potomac Edison Company, West Penn Power Company, Monongahela Power Company)

Unit		Year	Net Capability (MW) Summer	Winter	Fuel Type	Station Total
Existing System						
Albright	1	1952	73	76	Coal	
	2	1952	73	76	Coal	
	3	1952	137	140	Coal	292
Armstrong	1	1958	173	180	Coal	
	2	1959	176	180	Coal	360
Celanese	1	1937	7	10	Cogen.(Nat.Gas)	10
Ft. Martin	1	1967	276	276	Coal	
	2	1968	555	555	Coal	831
Hatfield's Ferry	1	1969	500	555	Coal	
	2	1970	500	555	Coal	
	3	1971	500	550	Coal	1,660
Harrison	1	1972	640	640	Coal	
	2	1973	640	640	Coal	
	3	1974	640	640	Coal	1,920
Hydro Stations (8)			7	10	Hydro	10
Lake Lynn	1-4	1926	52	52	Hydro	52
Milesburg	1	1950	22	23	Oil	
	2	1950	22	23	Oil	46
Mitchell	1	1948	85	89	Oil	
	2	1949	84	89	Oil	
	3	1963	282	291	Coal	469
Riverton	1	1949	38	39	Oil	39
Rivesville	5	1943	46	48	Coal	
	6	1951	91	94	Coal	142
R.P. Smith	3	1947	38	39	Coal	
	4	1958	89	90	Coal	129
Springdale	7	1945	85	86	Oil	
	8	1954	134	137	Oil	223
Willow Island	1	1949	57	58	Coal	
	2	1960	181	188	Coal	246
Additions and 1978-1987						
Celanese	1	1978	(7)	(10)	Cogen.(Nat.Gas)	
Pleasants	1	1979	626	626	Coal	
	2	1980	626	626	Coal	1,252
Lower Armstrong	1	1983	630	630	Coal	
	2	1984	630	630	Coal	
	3	1985	630	630	Coal	1,890
Davis	1	1986	250	250	Hydro	
	2	1986	250	250	Hydro	
	3	1987	250	250	Hydro	
	4	1987	250	250	Hydro	1,000
Long Range Additions, 1988-1997				3,455	Fossil	
				3,785	Nuclear	
				990	Hydro	
Total Existing System			6,203	6,429		
Total Net Additions to 1987			4,135	4,132		
Total Planned System to 1987			10,338	10,561		
Total Long Range Additions, 1988-1997				8,230		

Table I-19b. Baltimore Gas and Electric Company

Unit			Year	Net Capability (MW) Summer	Winter	Fuel Type	Station Total
Existing System							
Calvert Cliffs		1	1975	810	820	Nuclear	
		2	1977	810	820	Nuclear	1,620
Conemaugh[a]		1	1970	90	90	Coal	
		2	1971	90	90	Coal	
	IC	A-D	1970	1	1	Oil	181
C.P. Crane		1	1961	192	193	Oil	
		2	1963	192	193	Oil	
	GT	1	1967	14	17	Oil	398
Gould St.		3		103	104	Oil	103
Keystone (20.99%)[a]		1		176	179	Coal	
		2		177	178	Coal	
	IC	3-6		2	2	Oil	355
Notch Cliff	GT	1-4		64	68	Gas	
	GT	5-8		64	68	Gas	128
Perryman	GT	1-4		204	240	Oil	204
Philadelphia Rd.	GT	1-4		64	68	Oil	64
Riverside		1		58	59	Oil	
		2		59	60	Oil	
		3		61	62	Oil	
		4		78	79	Oil	
		5		65	66	Oil	
	GT	6		128	132	Oil	
	GT	7		22	25	Oil	
	GT	8		22	25	Oil	493
H.A. Wagner		1		137	138	Oil	
		2		134	135	Oil	
		3		319	321	Coal	
		4		398	400	Oil	
	GT	1		14	17	Oil	1,002
Westport		1		19	19	Oil	
		13		16	16	Oil	
		14		16	16	Oil	
		3		58	59	Oil	
		4		68	69	Oil	
	GT	5		118	132	Oil	295
Safe Harbor Entitlement			1931	152	152	Hydro	152
Bethlehem Steel Entitlement			--	167	169	Oil	167
Additions and (Removals), 1978-1987							
Brandon Shores		1	1982	610	620	Oil	
		2	1984	610	620	Oil	
Westport		1	1982	(19)	(19)	Oil	
		13	1982	(16)	(16)	Oil	
		14	1982	(16)	(16)	Oil	
Safe Harbor Entitlement			1985	125	125	Hydro	
Dickerson[a]		4	1987	400	400	Coal	
Westport		3	1987	(58)	(59)	Oil	
Long Range Additions, 1988-1997				400		Oil	
				1,600		Coal	
				1,300		Nuclear	
				800		Hydro	
				(955)		Oil	
Total Existing System				5,162	5,232		
Total Net Additions to 1987				1,636	1,655		
Total Planned System to 1987				6,798	6,887		
Total Long Range Additions, 1988-1997				3,145			

(a) Stations with joint ownership

Table I-19c. Delmarva Power and Light Company

Unit		Year	Net Capability (MW) Summer	Winter	Fuel Type	Station Total
Existing System						
Bayview	IC 1	1964	2	2	Oil	
	IC 2	1964	2	2	Oil	
	IC 3	1964	2	2	Oil	
	IC 4	1964	2	2	Oil	
	IC 5	1964	2	2	Oil	
	IC 6	1964	2	2	Oil	12
Cape Charles	IC 1	1947	0.8	0.8	Oil	
	IC 2	1936	0.8	0.8	Oil	1.6
Christiana	GT 11	1973	20	26	Oil	
	GT 14	1973	20	26	Oil	40
Conemaugh[a]	1		32	32	Coal	
	2		31	31	Coal	
	IC A-D		0.4	0.4	Oil	63.4
Crisfield	IC 1	1968	2.5	2.5	Oil	
	IC 2	1968	2.5	2.5	Oil	
	IC 3	1968	2.5	2.5	Oil	
	IC 4	1968	2.5	2.5	Oil	10
Delaware City	1	1956	27	27	Oil	
	2	1956	27	27	Oil	
	3	1961	65.5	66.5	Oil	
	GT 10	1968	17	21	Oil	136.5
Easton	IC 3	1936	0.5	0.5	Oil	
	IC 4	1941	0.6	0.6	Oil	
	IC 5	1947	0.8	0.8	Oil	
	IC 6	1950	1.2	1.2	Oil	
	IC 7	1954	2.4	2.4	Oil	
	IC 8	1957	2.5	2.5	Oil	
	IC 9	1961	2.2	2.2	Oil	
	IC 10	1966	3.5	3.5	Oil	
	11	1968	3.6	3.6	Oil	
	12	1970	4.1	4.1	Oil	
	13	1973	5.6	5.6	Oil	
	14	1973	5.6	5.6	Oil	32.6
Edge Moor	1	1951	70	70	Oil	
	2	1951	70	70	Oil	
	3	1954	82	82	Oil	
	4	1966	167	167	Oil	
	5	1973	412	412	Oil	
	GT 10	1963	15	15	Oil	816
Indian River	1	1957	89	90	Coal	
	2	1959	89	90	Coal	
	3	1970	162	165	Coal	
	GT 10	1967	17	19	Oil	357
Kent	GT 1	1964	12	15	Oil	12
Keystone[a]	1	1967	31	31	Coal	
	2	1968	31	32	Coal	
	IC 3-6	1968	0.4	0.4	Oil	62.4
Madison Street	GT 1	1962	11	14	Oil	
	IC 2	1948	0.5	0.5	Oil	11.5
McKee Run (Dover)	1	1961	15	15	Oil	
	2	1961	15	15	Oil	
	3	1975	105	105	Oil	135
Peach Bottom[a]	2	1967	79	79	Nuclear	
	3	1974	78	78	Nuclear	157
Salem[a]	1	1977	80	81	Nuclear	
	GT 3	1971	3	4		83

Table I-19c. Delmarva Power and Light Company (Continued)

Unit		Year	Net Capability (MW) Summer	Winter	Fuel Type	Station Total
Tasley	IC 1	1929	0.3	0.3	Oil	
	IC 2	1937	0.5	0.5	Oil	
	IC 3	1929	0.5	0.5	Oil	
	GT 10	1972	26	33	Oil	27.3
Vienna	5	1948	17	17	Oil	
	6	1949	17	17	Oil	
	7	1951	40	40	Oil	
	8	1971	150	155	Oil	
	GT 10	1968	17	19	Oil	
	IC A	1965	0.5	0.5	Oil	241.5
West	GT 1	1964	16	20	Oil	16
Additions and (Removals), 1978-1987						
Easton	21-22	1978	12.5	12.5	Oil	
Easton	3	1978	(0.5)	(0.5)	Oil	
Salem[(a)]	2	1979	83.0	83.0	Nuclear	
Indian River	4	1980	400.0	400.0	Coal	
Easton	4	1981	(0.6)	(0.6)	Oil	
Easton	23-24	1982	12.5	12.5	Oil	
Easton	7	1984	(0.5)	(0.5)	Oil	
Unidentified		1985	100.0	100.0	Oil	
Easton	25-28	1986	25.0	25.0	Oil	
Edge Moor	1	1987	(70.0)	(70.0)	Oil	
Vienna	5-6	1987	(34.0)	(34.0)	Oil	
Easton	5	1987	(0.8)	(0.8)	Oil	
Easton	8	1987	(0.5)	(0.5)	Oil	
Vienna	9	1987	400.0	400.0	Coal	
Long Range Additions, 1988-1997			200 1,300		Fossil Unidentified	
Total Existing System			2,214.8	2,266.8		
Total Net Additions to 1987			926.1	926.1		
Total Planned System to 1987			3,140.9	3,192.9		
Total Long Range Additions 1988-1997			1,500			1,500

(a) Stations with joint ownership

Table I-19d. Potomac Electric Power Company

Unit		Year	Net Capability (MW) Summer	Winter	Fuel Type	Station Total
Existing System						
Benning Road	10	1927	28	28	Oil	
	11(b)	1929	(23)	(23)	Oil	
	12	1931	28	28	Oil	
	13	1947	47	47	Oil	
	14	1952	26	26	Oil	
	15	1968	275	275	Oil	
	16	1972	275	275	Oil	679
Buzzard Point	1(c)	1933	(28)	(28)	Oil	
	2	1938	30	30	Oil	
	3	1940	48	50	Oil	
	4	1942	48	50	Oil	
	5	1943	48	50	Oil	
	6	1945	48	50	Oil	
	GT East	1968	124	160	Oil	
	GT West	1968	128	160	Oil	474
Chalk Point	1	1964	330	330	Coal	
	2	1965	330	330	Coal	
	3	1975	602	602	Oil	
	GT 1	1957	18	18	Oil	
	GT 2	1974	30	35	Oil	1,310
Conemaugh(a)	1	1970	83	83	Coal	
	2	1971	82	82	Coal	
	IC A-D	1970	1	1	Oil	166
Dickerson	1	1959	182	182	Coal	
	2	1960	183	183	Coal	
	3	1962	182	182	Coal	
	GT 1	1967	13	13	Oil	560
Morgantown	1	1970	556	556	Coal	
	2	1971	556	556	Coal	
	GT 1	1970	16	20	Oil	
	GT 2	1971	16	20	Oil	
	GT 3	1972	54	65	Oil	
	GT 4	1972	54	65	Oil	
	GT 5	1972	54	65	Oil	
	GT 6	1972	54	65	Oil	1,360
Potomac River	1	1949	86	87	Coal	
	2	1950	66	67	Coal	
	3	1954	102	102	Coal	
	4	1956	102	102	Coal	
	5	1957	102	102	Coal	458
Additions and (Renewals), 1978-1987						
Potomac River	3	1978	(1.3)	(1.3)	Coal	
	4	1978	(1.3)	(1.3)	Coal	
	5	1978	(1.4)	(1.4)	Coal	
	1-2	1979	(3.0)	(3.0)	Coal	
Dickerson	1-2	1979	(10)	(10)	Coal	
Chalk Point	1-2	1982	(8)	(8)	Coal	
	4	1982	600	600	Oil	
Benning	10-14	1982	(129)	(129)	Oil	
Buzzard	1-6	1982	(222)	(222)	Oil	
Dickerson(a)	4	1985	400	400	Coal	
Long Range Additions, 1988-1997			600		Unknown	
			500		Hydro/PS	
Total Existing System			5,007	5,142		
Total Net Additions to 1987			624	616		
Total Planned System to 1987			5,631	5,758		
Total Long Range Additions 1988-1997			1,100			

(a) Stations with joint ownership

(b) Benning No. 11 turbo-generator can only function as a replacement for No. 10 and No. 12 turbo-generators but cannot operate concurrently with them

(c) Buzzard No. 1 is "mothballed" and may be reactivated at a later date. The effective capability is currently considered to be 0.

Table I-20. Proposed new power plants and expansions of existing plants in Maryland

SITE	COUNTY	NEAREST TOWN	SITE SIZE	PLANT TYPE	PLANT SIZE	COMPLETION DATE	NOTES
ALLEGHANY POWER SYSTEM (POTOMAC EDISON)							
1. Point of Rocks	Frederick	Point of Rocks	829 acres	No plans. (Originally planned for nuclear)	No plans. (Originally planned for nuclear)	No plans	
BALTIMORE GAS & ELEC. CO.							
1. Brandon Shores	Anne Arundel	Riviera Beach	350 acres	Oil, with coal as alternate fuel	Two 600 MW units	1981, 1983	
2. Dickerson (existing station)	Montgomery	Dickerson	1000 acres	Coal	800 MW of new capacity	1985	Jointly owned with PEPCO. PEPCO is managing partner. BG&E share is 400 MW.
3. Soller's Point (existing station)	Baltimore	Dundalk	1000 acres	Gas turbine	100 MW total new capacity	1986	
4. Undetermined--northeastern Maryland region	Undetermined	Undetermined	800-1000 acres	Coal	800 MW	1987	
CONOWINGO POWER CO.							
1. Canal	Cecil	Chesapeake City	680 acres	No plans. (Listed as alternative nuclear site)	No plans	No plans	
2. Seneca Point	Cecil	Charlestown	500 acres	No plans. (Listed as an alternative nuclear site).	No plans	No plans	

Table I-20. Proposed new power plants and expansions of existing plants in Maryland (Continued)

SITE	COUNTY	NEAREST TOWN	SITE SIZE	PLANT TYPE	PLANT SIZE	COMPLETION DATE	NOTES
DELMARVA POWER & LIGHT CO							
1. Vienna (existing station)	Dorchester	Vienna	955 acres	Coal	400 MW	1987	
EASTON UTILITIES COMM.							
1. Easton Plant 2 (existing station)	Talbot	Easton	7 acres	No. 2 Oil	37.5 MW	1982, 1986	
POTOMAC ELECTRIC POWER CO							
1. Chalk Point (existing station)	Charles	Benedict	1160 acres	Oil	600 MW	1982	
2. Dickerson 4 (existing station)	Montgomery	Dickerson	1004 acres	Coal	800 MW	1985	Jointly owned with BG&E. PEPCO is managing partner. PEPCO share is 400 MW.
3. Undetermined	Undetermined	Undetermined	1000 acres	Pumped Storage	1000 MW	Undetermined	
4. Douglas Point	Charles	Nanjemoy	1400 acres	Nuclear	2200 MW	Undetermined	

Table I-20. Proposed new power plants and expansions of existing plants in Maryland (Continued)

SITE	COUNTY	NEAREST TOWN	SITE SIZE	PLANT TYPE	PLANT SIZE	COMPLETION DATE	NOTES
SOUTHERN MARYLAND ELECTRIC COOPERATIVE							
1. Della Brooke Farm	St. Mary's	Oraville	300 acres	No plans	No plans	No plans	
MARYLAND POWER PLANT SITING PROGRAM SITES							
1. Elms	St. Mary's	St. Mary's City	1000 acres	No plans	No plans	No plans	Site is designated for PEPCO. No plans have been announced for its use.
2. Bainbridge	Cecil	Port Deposit	937 acres	No plans	No plans	No plans	Site is in process of acquisition from U.S. General Services Administration. Site has been designated for the BG&E system. No plans have been announced for its use. Philadelphia Electric Co. (Conowingo) has indicated interest in sole or joint use of site.

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16. Case No. 6807, Maryland Public Service Commission.

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21. Appendix A; Appendix B; Letter from Mr. M. Kahal, J.W. Wilson and Associates to Mr. H. Mueller, reporting updated PEPCO forecast, November 17, 1978; testimony of various utilities in Maryland Public Service Commission Cases 6807 and 7259; "Coordinated Regional Bulk Power Supply Programs," Op. Cit.; "MAAC Systems Plant," Op. Cit.

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CHAPTER II

AIR IMPACT

The quality of the air around us is measured in terms of the ground-level concentration of certain pollutants. Changes in this air quality is the result of several factors such as emission of pollutants, the atmospheric transport and dispersion of the pollutants, and chemical and mechanical processes acting on the pollutants. The impact of the pollutants on man and materials depends on frequency, duration, and level of exposure, and on the chemical reactivity of the pollutants, as well as the susceptibility of the receptors to damage. To protect man, primary air quality standards have been established while secondary standards protect against damage to materials. The interplay of these various factors is discussed in this Chapter.

In sections A to D, we will discuss the nature of power plant emissions, the health effects of the pollutants, standards protecting human health, and, finally, the present levels of pollution. Section E will focus upon emission control of SO_2, the major power plant pollutant. Mathematical modeling of pollutant plume dispersion, often a central factor in licensing procedures, is discussed in Section F. Finally, the provisions and implications of the Clean Air Act Amendments of 1977 are reviewed in Section G.

A. Sources and Nature of Emissions

Airborne wastes from power plant combustion include sulfur oxides (SO_x), possibly mixed with sulfates and sulfuric acid mist, nitrogen oxides (NO_x), particulates, and, to a lesser degree, hydrocarbons, carbon monoxide, flourides, carbon dioxide, and traces of organic and metallic compounds. The rate of release depends on the type of fuel, power level, the type of boiler firing, and the efficiency of pollution control devices such as precipitators and scrubbers.

During combustion, sulfur in coal and oil is almost completely converted to SO_2 and emitted through the stack, unless it is absorbed in a scrubber. The preponderance of NO_x emitted is due to reactions between O_2 and N_2 in the air at elevated temperatures. Thus, NO_x emission rates are sensitive to flame temperature and amount of excess air entering the furnace. Particulates, mainly non-combustible fuel residues (silicates, metal salts, sodium chloride) and incompletely burned organic materials, are often removed from the flue gas by precipitators.

Table II-1 shows Maryland area power plant (Figure II-1) emissions for 1974 and 1975 and the total state emission inventory (1) by source category as obtained from measurements and theoretical calculations. It can be seen that, of the five major pollutants emitted by all sources in Maryland, power plants contribute negligible amounts of carbon monoxide and hydrocarbons, about 30 percent of the NO_x, 32 percent of the particulate, and 69 percent of the sulfur oxides. Power plant contributions to ground-level concentrations of these pollutants are, however, much smaller than these emission data indicate (see Section D).

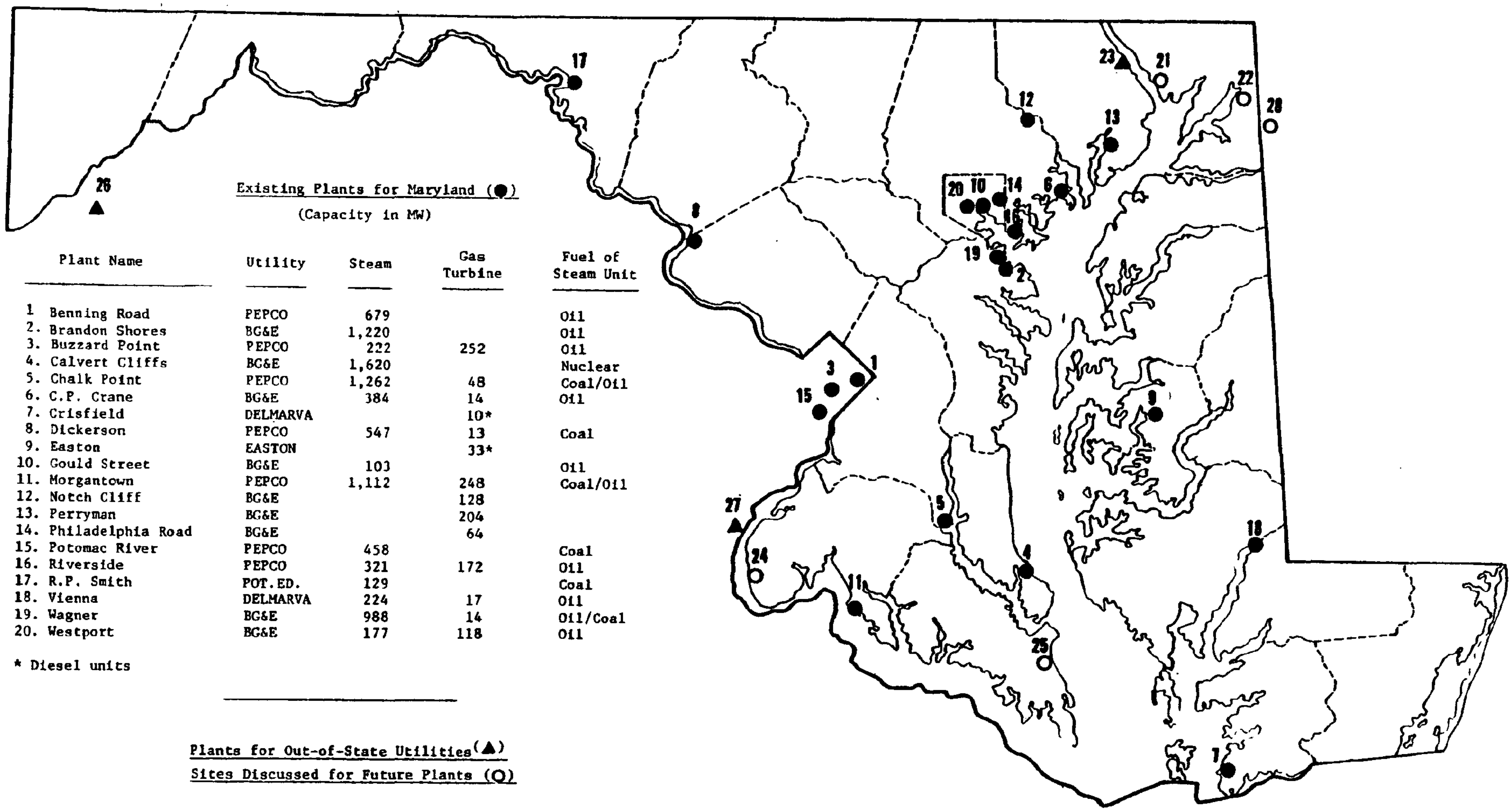
Table II-1. Statewide total emissions inventory, 1974 and 1975

	Heating		Power Plants		Mobile Sources		Process		Refuse		Total	
	1974	1975	1974	1975	1974	1975	1974	1975	1974	1975	1974	1975[a]
Particulate												
Tons/yr	12,200	9,900	47,500	27,300	17,600	18,600	22,000	27,700	4,300	1,500	103,500	85,400[b]
% of total	11.8	11.6	45.8	32.0	17.0	21.7	21.2	32.4	4.2	1.7		
Sulfur Oxides												
Tons/yr	62,200	60,000	248,800	283,500	18,100	26,600	45,500	39,300	800	400	375,500	409,900
% of Total	16.6	14.6	66.3	69.2	4.8	6.5	12.1	9.6	0.2	0.1		
Hydrocarbons												
Tons/yr	3,200	3,700	2,100	2,800	198,100	259,900	77,400	44,900	1,100	300	281,900	336,100[c]
% of Total	1.1	1.1	0.8	0.8	70,3	77.3	27.5	13.4	0.4	0.1		
Nitrogen Oxides												
Tons/yr	47,400	46,800	102,900	104,900	154,200	189,400	39,600	17,500	1,000	400	342,900	359,100
% of Total	13.7	13.0	29.8	29.2	44.7	52.7	11.5	4.9	0.3	0.1		
Carbon Monoxide												
Tons/yr	9,900	8,700	3,900	4,300	1,374,500	1,808,000	112,200	85,200	3,800	4,000	1,504,300	1,915,400
% of Total	0.6	0.5	0.3	0.2	91.4	94.4	7.5	4.5	0.2	0.2		

(a) Includes a miscellaneous category.

(b) These are "man-made" particulate emissions. Particulate "emissions" due to natural causes, e.g., wind blown dust and pollen, vary widely with place and time and can exceed man-made emissions by an order of magnitude.

(c) In addition, about 150,000 tons per year is released from asphalt roads in the State. This quantity can be reduced to 20,000 to 25,000 tons per year by current use of a different type of road tar. Emission from an asphalt surfaced road decreases significantly over a period of one to two years.



Existing Plants for Maryland (●)

(Capacity in MW)

Plant Name	Utility	Steam	Gas Turbine	Fuel of Steam Unit
1 Benning Road	PEPCO	679		Oil
2. Brandon Shores	BG&E	1,220		Oil
3. Buzzard Point	PEPCO	222	252	Oil
4. Calvert Cliffs	BG&E	1,620		Nuclear
5. Chalk Point	PEPCO	1,262	48	Coal/Oil
6. C.P. Crane	BG&E	384	14	Oil
7. Crisfield	DELMARVA		10*	
8. Dickerson	PEPCO	547	13	Coal
9. Easton	EASTON		33*	
10. Gould Street	BG&E	103		Oil
11. Morgantown	PEPCO	1,112	248	Coal/Oil
12. Notch Cliff	BG&E		128	
13. Perryman	BG&E		204	
14. Philadelphia Road	BG&E		64	
15. Potomac River	PEPCO	458		Coal
16. Riverside	PEPCO	321	172	Oil
17. R.P. Smith	POT.ED.	129		Coal
18. Vienna	DELMARVA	224	17	Oil
19. Wagner	BG&E	988	14	Oil/Coal
20. Westport	BG&E	177	118	Oil

* Diesel units

Plants for Out-of-State Utilities (▲)

Sites Discussed for Future Plants (○)

21. Bainbridge
22. Chesapeake City
23. Conowingo
24. Douglas Point
25. Elms
26. Mount Storm (VEPCO)
27. Possum Point (VEPCO)
28. Summit

Figure II-1. Power plants in the Maryland region

B. Health Effects

Numerous investigations have sought to document the health effects of exposure to air pollutants for concentrations normally encountered at ground level (2).

Scientific consensus on the interpretation of dose-response data has led to enactment of Federal and State Ambient Air Quality Standards, which include sufficient safety margins (as a hedge against uncertainty in the data) to protect even the most sensitive segments of the population (3). Emission standards and fuel use regulations have also been promulgated as a means of obtaining compliance with Ambient Air Quality Standards by regulating pollution at its source.

There is an increasing realization that few of the pollutants for which standards have been established act directly or alone in producing medical effects. Toxicological studies indicate that the chemical transformation products of SO_2, mainly sulfates, are more likely than SO_2 alone to be responsible for many of the adverse health effects associated with ambient sulfur oxides. In the absence of other pollutants, such as ozone and particulates, SO_2 is a mild respiratory irritant; but there is evidence that certain sulfate compounds (especially sulfuric acid aerosols) are more severe irritants (4).

For instance, epidemiological studies in several U.S. cities have associated high daily or annual sulfate levels with increased frequency of asthma attacks, intensification of symptoms in cardio-pulmonary patients, decreased ventilatory function in school children, and symptoms of acute and chronic respiratory disease in children and adults. Taken together, findings of the toxicological and epidemiological studies suggest that sulfate compounds may be the agents responsible for the observed excess mortality associated with high SO_2 levels (5).

Similarly, many hydrocarbons have been found not to be medically harmful, but they take part in a chain of photochemical reactions with NO_x and other atmospheric constituents to form oxidants, such as ozone (O_3), which are major irritants (6).

Thus, in many cases, the emitted pollutants are only precursors to the substances which actually constitute the health hazard. Since these relationships between precursors and their end products are complex and often poorly known -- even the origin of some of the precursors (e.g., hydrocarbons) is not well understood -- the Environmental Protection Agency (EPA) has found it premature to establish standards for "ultimate pollutants" such as sulfates. Until more is known about the reaction processes, it is considered sound and meaningful strategy to control the five major "criteria" pollutants: particulate matter, sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide, and hydrocarbons.

C. Standards

Ambient air quality is measured and defined as ground-level concentration of pollutants. Federal and State agencies are attempting to attain and maintain good air quality by regulation of: (a) pollutant ground-level concentrations, through ambient air quality standards, (b) source emissions, through source emission standards, and (c) the quality of fuels burned, through sulfur content standards.

Ambient Air Quality Standards have been established by the Federal Environmental Protection Agency for ground-level concentrations of certain pollutants.* The National Ambient Air Quality Standards (NAAQS) (7) are listed in Table II-2. The National Primary standards are designed to protect human health (i.e., medical effects of pollution), whereas the secondary standards are concerned with the protection of human welfare (i.e., the material and aesthetic effects of pollution).

Emission Standards were established by EPA in December, 1971 under authority of the Clean Air Act of 1970 for new sources, i.e., sources beginning operation after 1977 (8). To satisfy the requirements of the Clean Air Act Amendments of 1977, EPA has proposed new standards of performance for stationary sources (8). These standards would apply to utility steam generating units for which construction is commensed after September 18, 1978. Table II-3 compares these New Source Performance Standards (NSPS).

Fuel Standards have been imposed by the State in the form of limits on the sulfur content in coal and oil that can be used in specific power plants and in oil for home consumption (9).

In addition to the standards, a comprehensive body of guidelines and regulations have been developed at national and state level to control and maintain air quality. Several of these regulations will be discussed in subsequent sections.

D. Status and Trends in the Maryland Airshed

In general, all areas of the State are currently in compliance with the National Ambient Air Quality Standards, except for the hydrocarbon and photochemical oxidant standards which are violated throughout the State, and suspended particulate and carbon monoxide standards which are violated in part of the Baltimore area and part of the Potomac Valley (10) in Allegany County.

Trends in ambient air quality can be determined from analyses of ground-level concentration data from air quality monitoring stations. The national air quality trends presented below are based on data from the U.S. Environmental Protection Agency's National Aerometric Data Bank (NADB). These data are gathered primarily from State and local air pollution control agencies through their monitoring activities (11).

Maryland data are reported by the State's Bureau of Air Quality and Noise Control (BAQNC) which has stations throughout the State mainly in the urban areas (12). Because of the non-uniform distribution of stations, the ground-level concentrations reported may not be representative of the overall status

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* Maryland Ambient Air Quality Standards were repealed by HB 1146 in the 1978 legislative session. The National Ambient Air Quality Standards therefore apply to the State.

Table II-2. Federal ambient air quality standards

	National			
	Primary		Secondary	
	µg/m³	ppm	µg/m³	ppm
Sulfur Oxides				
Annual Arithmetic Mean	80	0.03		
24-hr Maximum[(a)]	365	0.14		
3-hr Maximum[(a)]			1,300	0.5
1-hr Maximum[(b)]				
Suspended Particulate Matter				
Annual Geometric Mean	75		60	
24-hr Maximum[(a)]	260		150	
Carbon Monixide				
8-hr Maximum[(a)], mg/m³	10	9	10	9
1-hr Maximum[(a)], mg/m³	40	35	40	35
Hydrocarbons (non-methane)		(carbon)		(carbon)
3-hr (6-9AM) Maximum[(a)]	160	0.24	160	0.24
Nitrogen Dioxide				
Annual Arithmetic Mean	100	0.05	100	0.05
Photochemical Oxidants		(ozone)		(ozone)
1-hr Maximum[(c)]	240	0.12	240	0.12

(a)Not to be exceeded more than once per year

(b)Not to be exceeded more than once per month

(c)The ozone standard was changed from 160 µg/m³ and 0.08 ppm in January 1979 (regulations to be published in Federal Register week of February 5, 1979)

Table II-3. Existing new source standards of performance for fossil fuel fired steam generators (1971) and proposed standards (1978)

Pollutant	Old Standard	Proposed Standard
Particulate matter	0.10 lb per million BTU heat input, maximum 2-hr average.	0.030 lb/per million BTU heat input, maximum 2-hr average.
	20 percent opacity (6-min average); except that 40 percent opacity is permissible for not more than 2 min in any hour.	Same
Sulfur dioxide	0.80 lb per million BTU heat input, maximum 2-hr average when liquid fossil fuel is burned.	Same[(a)]
	1.2 lbs per million BTU heat input, maximum 2-hr average when solid fuel is burned.	Same[(a)]
		85 percent reduction of uncontrolled emission[(b)]
Nitrogen oxides	0.2 lb per million BTU heat input, maximum 2-hr average, expressed as NO_2, when gaseous fossil fuel is burned.	Same
	0.30 lb per million BTU heat input, maximum 2-hr average, expressed as NO_2, when liquid fossil fuel is burned.	Same
	0.70 lb per million BTU heat input, maximum 2-hr average, expressed as NO_2, when solid fossil fuel (except lignite) is burned.	0.60 lb per million BTU heat input, maximum 2-hr average, expressed as NO_2, from combustion of bituminous coal.
		0.50 lb per million BTU heat input, maximum 2-hr average, expressed as NO_2, from combustion of subbituminous coal, shale oil, or any solid liquid or gaseous fuel derived from coal.

(a) Except for 3 days per month; compliance to be determined on a 24-hr daily basis.

(b) Except for 3 days per month; when only 75 percent reduction is required. For sources emitting less than 0.20 lb/million BTU, the percent reduction requirement would not apply.

of air quality, but the trends, or changes, at these stations do indicate the state-wide trends. However, since many stations have been moved over the years and the measurement methods have changed, it is sometimes difficult to find stations with sufficient continuity to establish long-term trends.

Emission data are obtained from estimates of indicators such as fuel consumption, production rates, control efficiencies, and vehicle miles traveled. Average emission factors, which relate these indicators to emission rates for specific source categories, are used to derive total emissions (13).

In the following sections, national and State trends in air quality are discussed for the three main power plant pollutants.

Total Suspended Particulates (TSP)

The national trend for TSP ground-level concentrations shows considerable improvement from 1960 to 1975 at 95 urban stations throughout the nation (14). The urban composite average of the annual geometric mean decreased from about 110 $\mu g/m^3$ in 1960 to 72 $\mu g/m^3$ in 1975, just below the primary national standard of 75 $\mu g/m^3$. In a much broader sample of 2350 stations throughout U.S.A. (11) the recent trend, from 1970 to 1976 is shown in Figure II-2A.

Peak daily concentrations are shown in Figure II-2B for the same stations. Corresponding emission trends are shown in Figure II-2C. Additional particulate emission control is not expected to produce much improvement in air quality, since many areas have a high background concentration of natural origin (e.g., windblown dust and pollen).

There has also been a downward trend in TSP concentrations in Maryland over the last 10 to 15 years (12). Because of changes in locations and deletion and additions of stations, the trends may not be immediately evident from an inspection of the annual air quality data reports. Figure II-3 shows the number of stations violating state standards for annual arithmetic mean of TSP out of a group of 35 measuring stations which have been in operation at the same location for the six years, and where each station has had at least one violation in one of the six years. Improvement is indicated by decreasing violations. Figure II-3 shows the trends for these stations from 1971 to 1976, and the trend for all Maryland stations is shown in Figure II-4.

A closer inspection of the air quality data from the Bureau of Air Quality and Noise Control reveals that there are two general non-attainment areas: along the Potomac Valley from the Bloomington/Luke area to Cumberland, and in the southeastern part of Baltimore City. The importance of these non-attainment areas to the siting of future power plants will be discussed in Section G.

The problem in maintaining a satisfactory air quality in the greater Baltimore area has been investigated (15) through the use of an Air Quality Display Model (AQDM) (16). This model calculates ground-level concentration of pollutants using a Gaussian plume model with appropriate atmospheric stability and wind conditions established from 5 years of meteorlogical records. Discrete (e.g., industrial and commercial) and distributed (e.g., home heating) emission sources are used as inputs to the model. Vehicular emissions are also

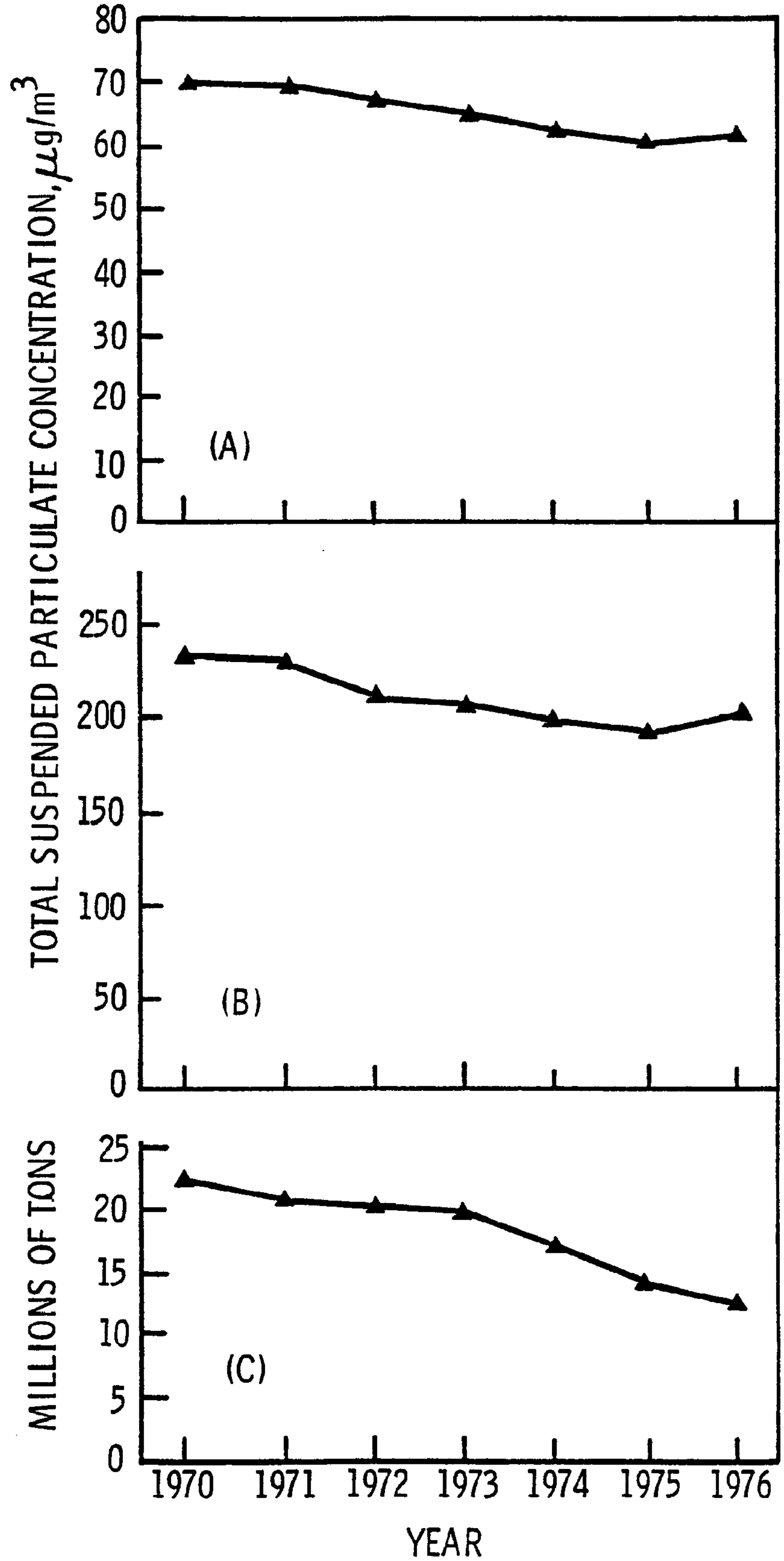

Figure II-2. (A) Composite average of annual mean total suspended particulate concentration at 2,350 U.S. sampling sites

(B) Composite average of peak daily total suspended particulate concentration at 2,350 U.S. sampling sites

(C) Total suspended particulate emission estimates for U.S.

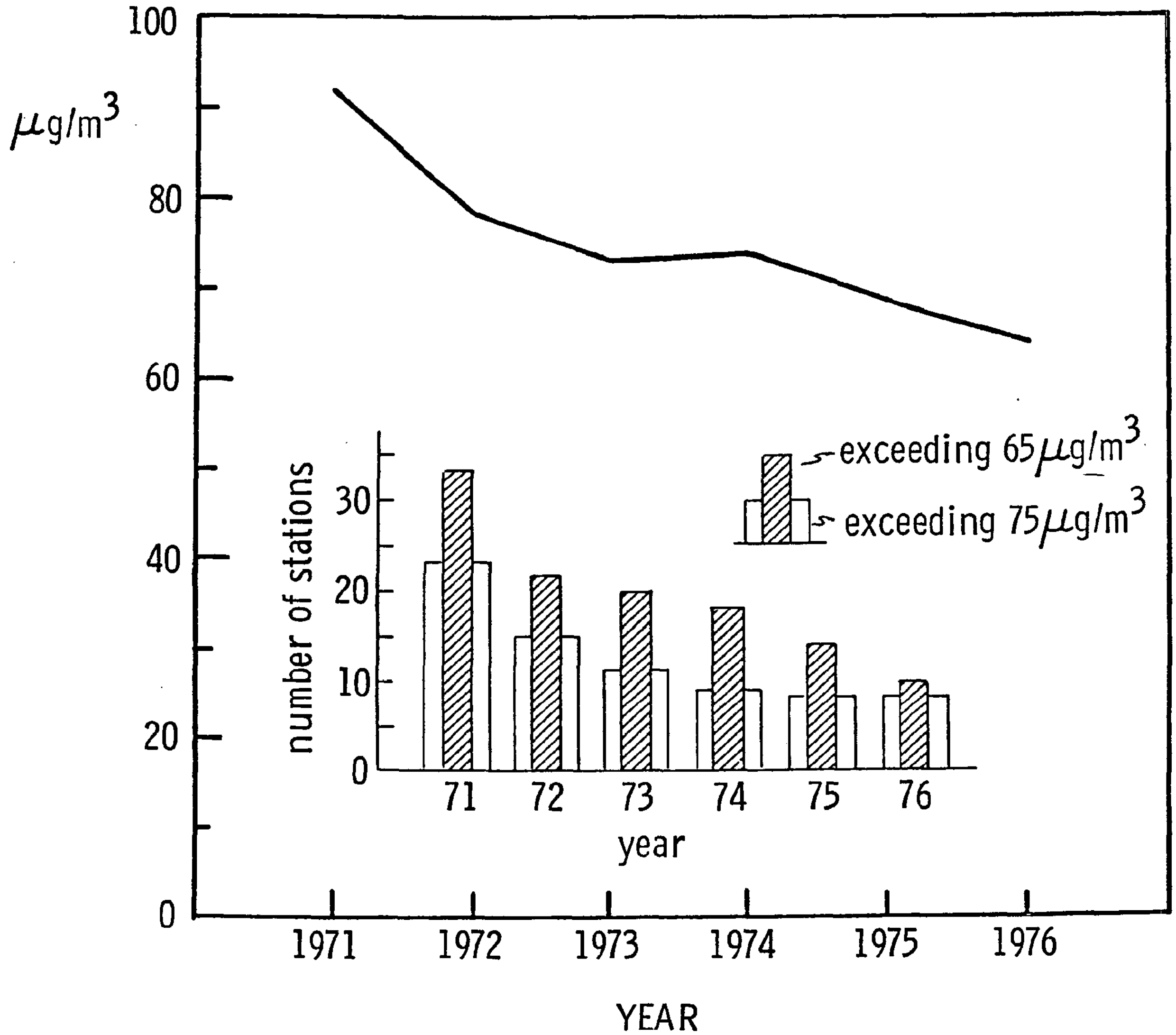

Figure II-3. The bar graph (insert) shows the number of violations of the State standards for total suspended particulates (TSP) for a set of 35 stations throughout Maryland. These stations have a continuous record since 1971 and exceeded one or the other of the "more adverse range" or "serious level" State standards at least once during this period. The graph on the top shows the composite means of the annual average of TSP for these stations. (The State Standards have since been replaced by Federal primary and secondary standards of 75 $\mu g/m^3$ and 60 $\mu g/m^3$, respectively.)

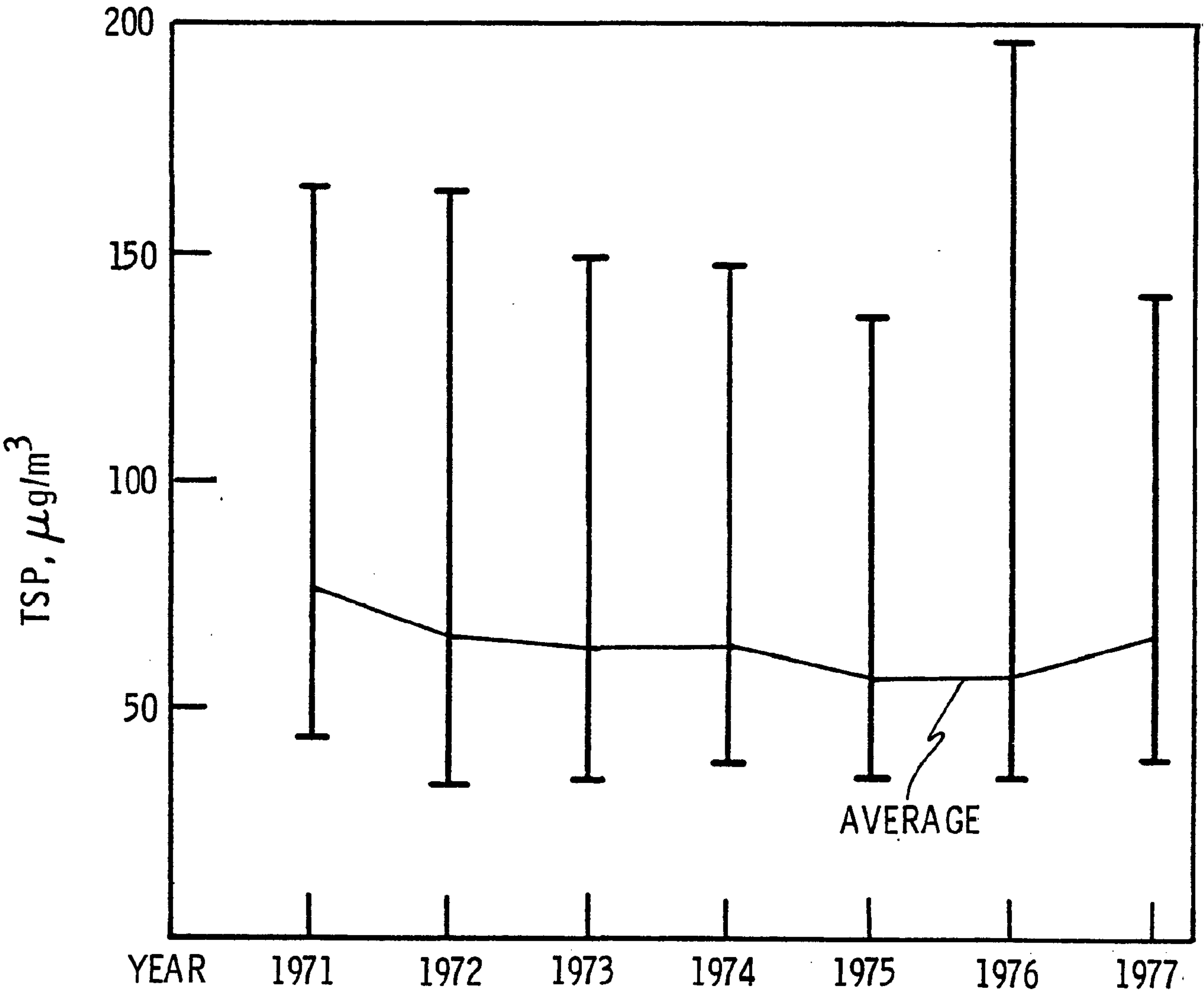

Figure II-4. Composite mean of the annual averages of total suspended particulates (TSP) for all Maryland stations with a continuous record for the six years shown. The bars indicate the range of values for the stations.

accounted for using known traffic density and emission rates per miles travelled. A set of baseline emission conditions have thus been established for 1973, and forward projections to 1985 have been made using expected rates of change in economic activities (including new power plants such as Brandon Shores) and population shifts, from Department of State Planning data.

The AQDM can only calculate ground-level concentrations under prevailing average conditions in a gross sense, and it does not account for localized effects (caused by conditions such as local wind patterns, detailed topography or any shielding effect) at any particular spot where measurements may be taken at a monitoring station. Although all known major emission sources are in the model, unknown small sources may be located near a monitoring station and affect its readings, although their impact on overall air quality may be negligible. Therefore, one must not expect a point by point agreement between calculated and measured value in any one area, particularly in an urban area. However, general overall distributions and trends should agree between the model and field measurements.

Figure II-5 shows the expected distribution of annual average TSP for the Baltimore area in 1973, 1980, and 1985, based on model runs (15). Used as trend indicators, the model runs show that the air quality of the region will change little over the next 10 years, and that the existing pattern of violations of the annual average will continue unless control efforts are intensified.

Other calculations for the 24-hour average indicate that this standard also will be violated regularly throughout a sizeable part of Baltimore City and the suburbs surrounding the industrial area (Essex, Sollers Point, Lansdowne, and Glen Burnie) unless corrective measures are taken (15).

An additional problem with the TSP levels (not considered in the model runs) has resulted from the federal coal conversion program. At the present time, Morgantown, Dickerson, and Chalk Point Units 1 and 2, are burning 100% coal (as coal deliveries and emission constraints allow), as opposed to a coal /oil mixture. In the Baltimore area, Wagner Units 1 and 2, Riverside and Crane, are now burning oil and are under active consideration for coal conversion. The Department of Energy (DOE) is studying the impacts of these conversions and is expected to announce the results of its study by the end of 1979.

To meet State emission control limitations at these three plants would require substantial investment in precipitators. Recent estimates range from 18 to 30 million dollars per unit (17). Even with this equipment, the additional impact of coal burning on the Baltimore Airshed may be sufficient to warrant a negative decision for conversion of one or more of these plants. The DOE study will include an evaluation of this impact.

Two power plants, Chalk Point and Dickerson, are presently not in compliance with particulate emission limitations. The precipitators on the older units at these plants need to be upgraded to modern standards. Plans have been submitted that will achieve final compliance by July 1, 1979 in accordance with the Clean Air Act Amendments. The new Chalk Point #3 unit was recently damaged by fire. Final repairs and upgrading started in January 1978. No final compliance deadline has been set.

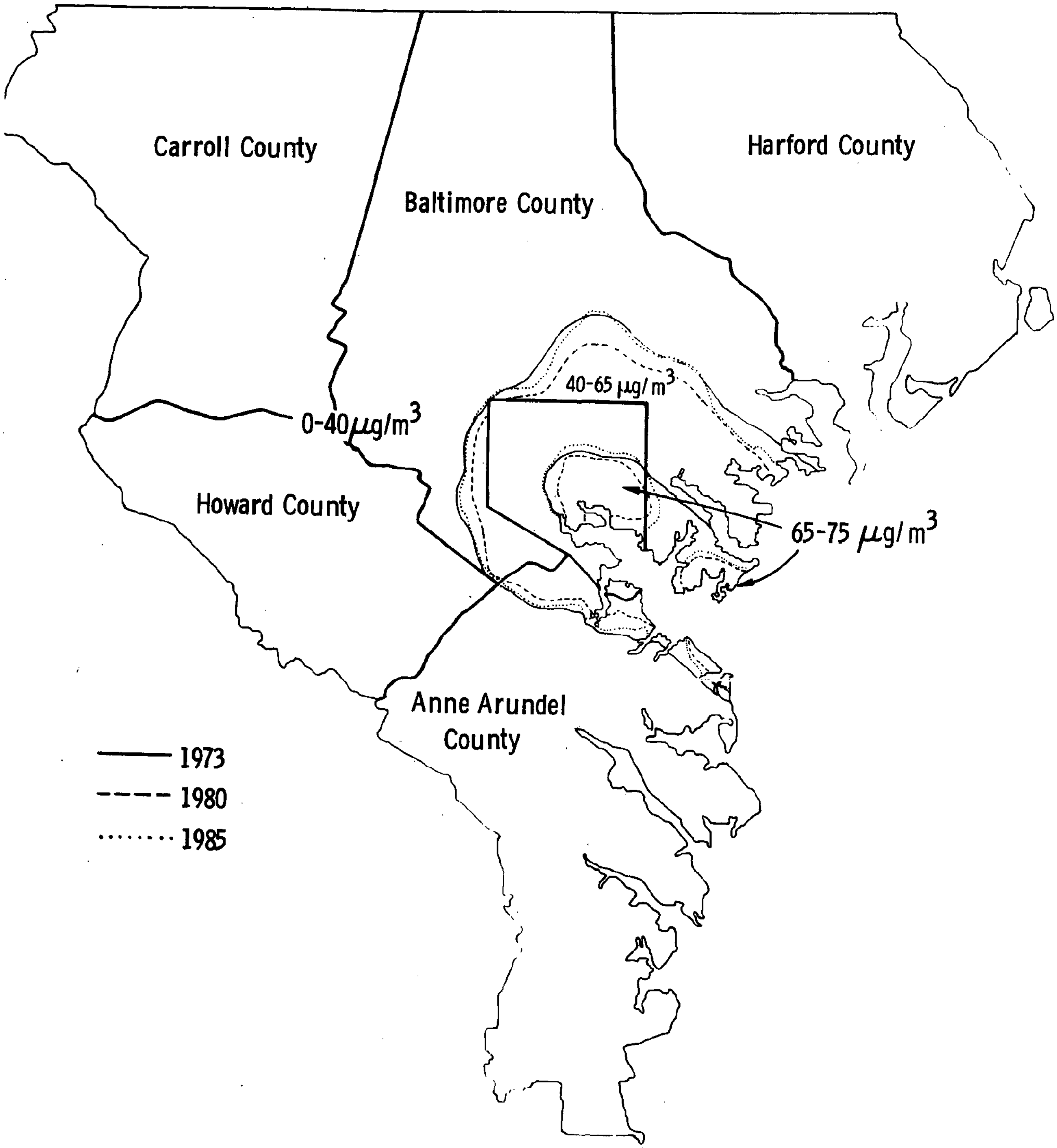

Figure II-5. Estimates of total suspended particulates ground-level concentrations by the Maryland Bureau of Air Quality and Noise Control

Sulfur Dioxide (SO_2)

From 1964 to 1975 there was a decrease of about 60 percent in the composite annual SO_2 arithmetic means from 32 stations throughout the U.S. (14). Most of the improvement (a 50 percent decrease in the composite mean) occurred between 1964 and 1971 and was much greater for the "dirty" areas than for the "clean" areas. In the industrial northeast, the "dirtiest" region, the annual mean fell from almost 90 $\mu g/m^3$ in 1964 to a little above 40 $\mu g/m^3$ in 1971.

Recent trends (1970-1976) are shown in Figure II-6 for a much broader sample of 722 stations throughout the U.S.A. (11). Plots of national emissions (Figure II-7) show that, during the period when SO_2 ground-level concentrations decreased by 50 percent (1964 to 1971), the total SO_2 emissions increased by more than 20 percent (27 to 33 million tons per year). This apparent inconsistency can largely be explained by the following considerations. First, most air quality monitoring stations are located in urban areas whereas large power plants, the most important source of the increase in emission (Figure II-7), are increasingly being located in rural areas. They contribute little to urban pollution levels because of distance, their tall stacks, and high buoyancy flux; all of which increase the SO_2 dispersion. Secondly, the SO_2 emissions in and around the cities have decreased markedly as clean fuels, such as low sulfur oil and gas, have replaced coal and high sulfur oil for space heating in residential and commercial establishments. The effect of this fuel replacement is small on national emissions but large on local air quality.

Maryland SO_2 data generally follow the national trends up to 1970 (12). Since 1972, there has been some improvement in SO_2 ground-level concentrations, which have been in compliance with the air quality standards. Figure II-8 shows the trend at several stations across the State since 1973. Figure II-9 shows a seasonal trend in the SO_2 concentration (measured by the flame photometric method). Higher levels in the heating months (first and fourth quarters) further indicates that a large contribution to the SO_2 level comes from local sources, primarily space heating units (most Maryland power systems have higher summer than winter loads, see Chapter I).

Predictions by the AQDM for 1973, 1980, and 1985 (see Figure II-10) indicate that the SO_2 air quality will change little through these years, and that no violations of current SO_2 standards are expected (15). As with TSP, the heaviest SO_2 pollution will be in the industrialized southeastern part of the city and the adjoining suburbs.

A special study was made using the AQDM to compare the contribution from BG&E power plants to the SO_2 level in this critical industrialized area of Baltimore to that from a group of 23 industrial sources (17). Table II-4 shows the calculations of the BG&E plants contributions to the SO_2 ground-level concentration. The detailed data (not shown here) reveal that, as a group, these power plants are either the second or third largest contributor at each of the receptor points shown. However, their total contribution to the ground-level concentration (about 17 percent) is far below their contribution to SO_2 emission (55 percent). In contrast, the 23 other industrial sources contributed 70 percent or more of the ground-level SO_2 concentration (at most of the receptor points) from only 31 percent of the total emissions. It appears that distributed sources, e.g., from home heating units, are not adequately accounted for in the

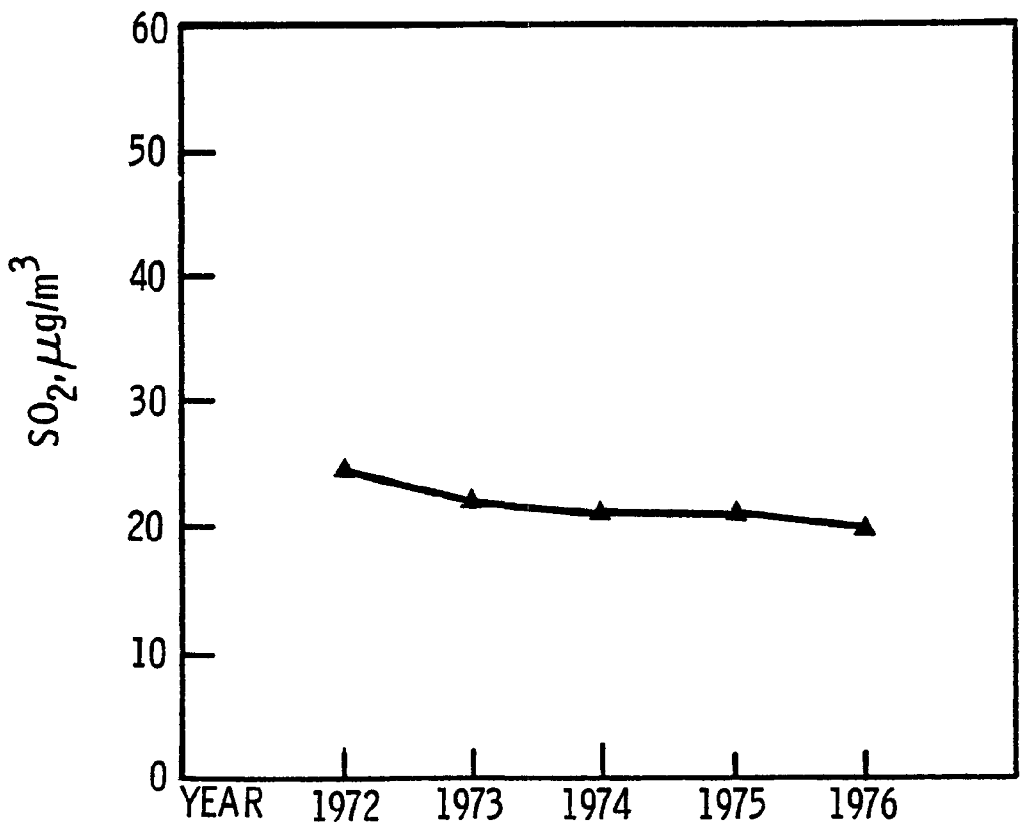

Figure II-6. Composite average of annual mean SO_2 concentrations at 722 U.S. sampling sites.

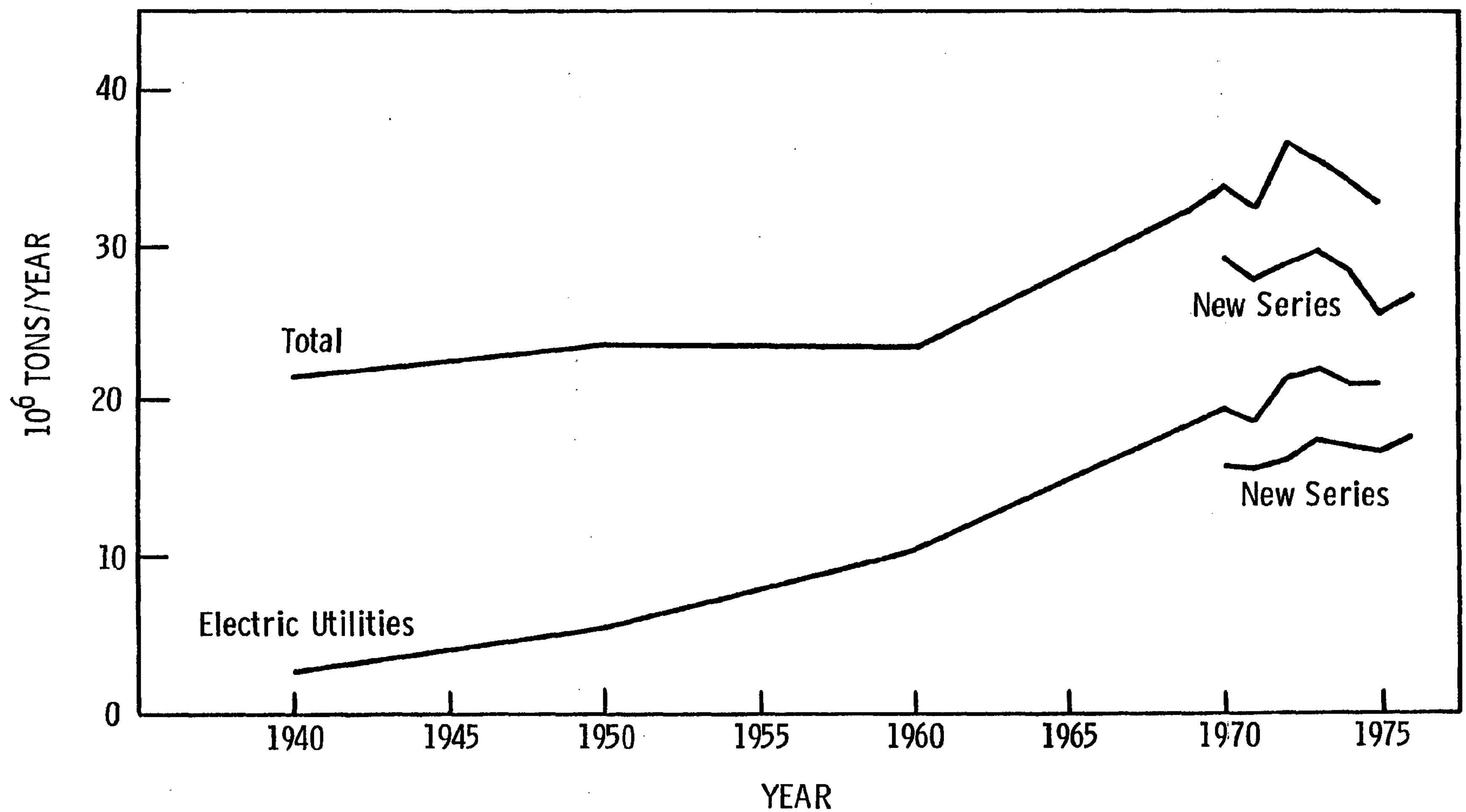

Figure II-7. Long-term trends in U.S. SO_2 emissions. New Series starting in 1970 are based on improved estimating techniques.

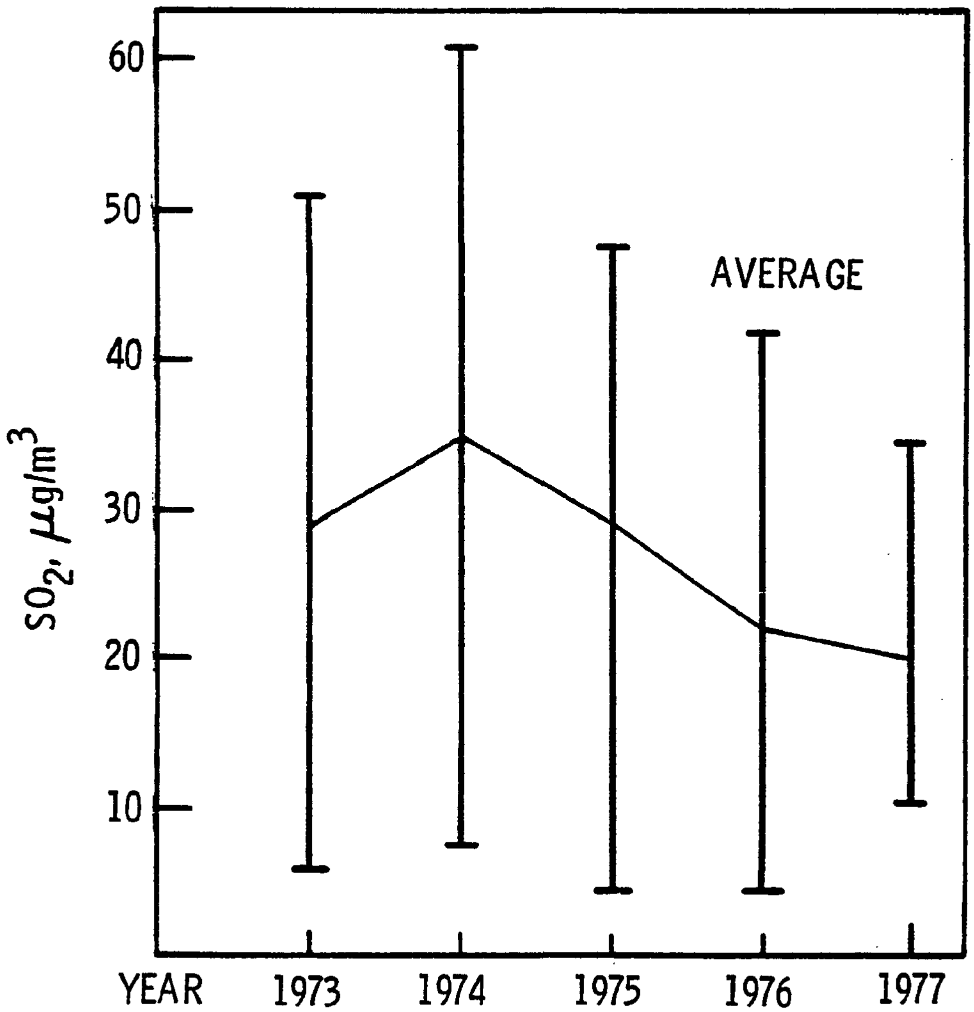

Figure II-8. Composite mean of annual arithmetic averages of SO_2 for those stations in Maryland with complete data for entire year. Measurements are by the flame photometric method, which was introduced in 1972, and has full-year coverage since 1973. Ranges of values indicated by the bars.

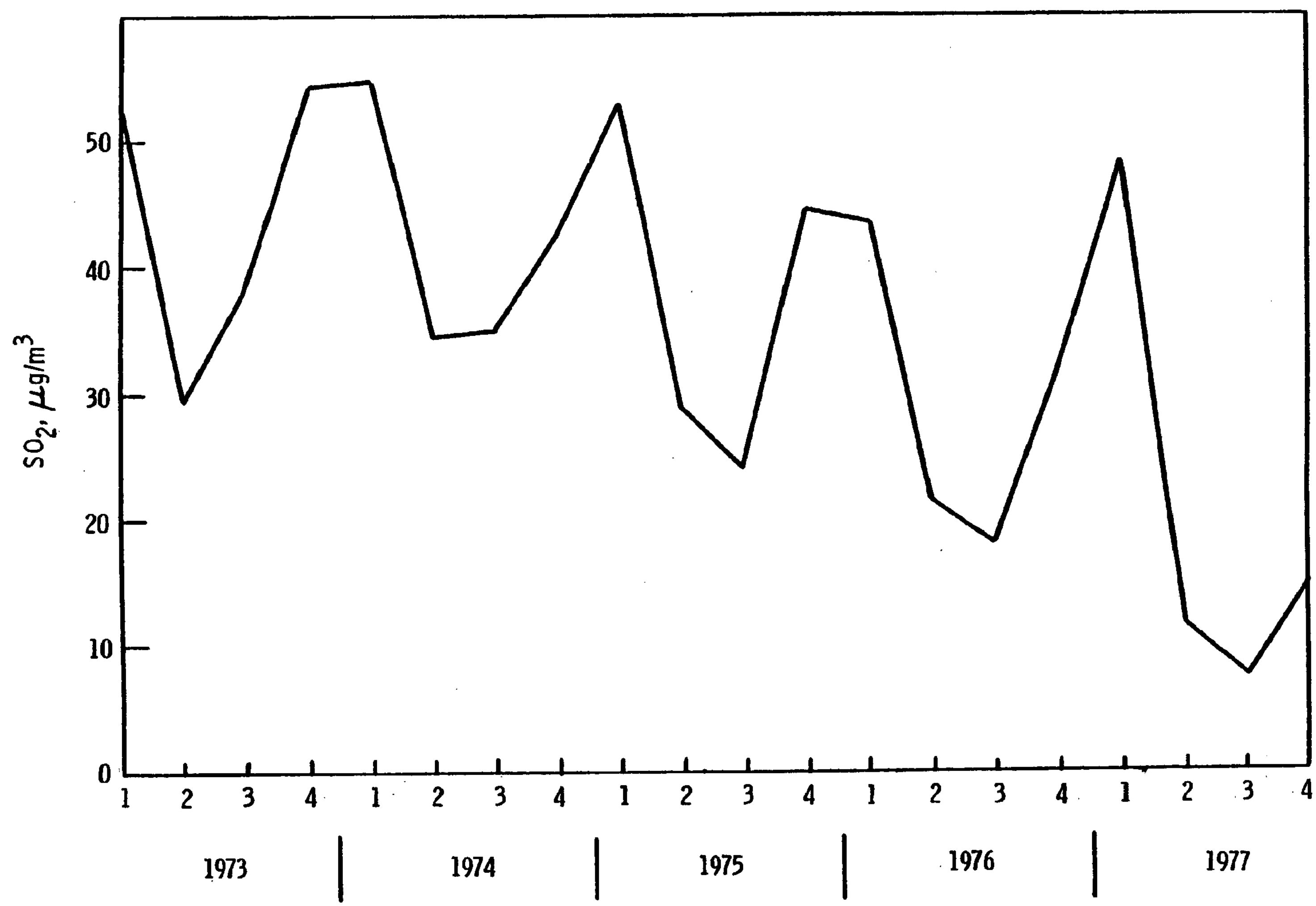

Figure II-9. Seasonal trend in SO_2 ground-level concentration. Average for all Baltimore City and County stations (Flame Photometric Method).

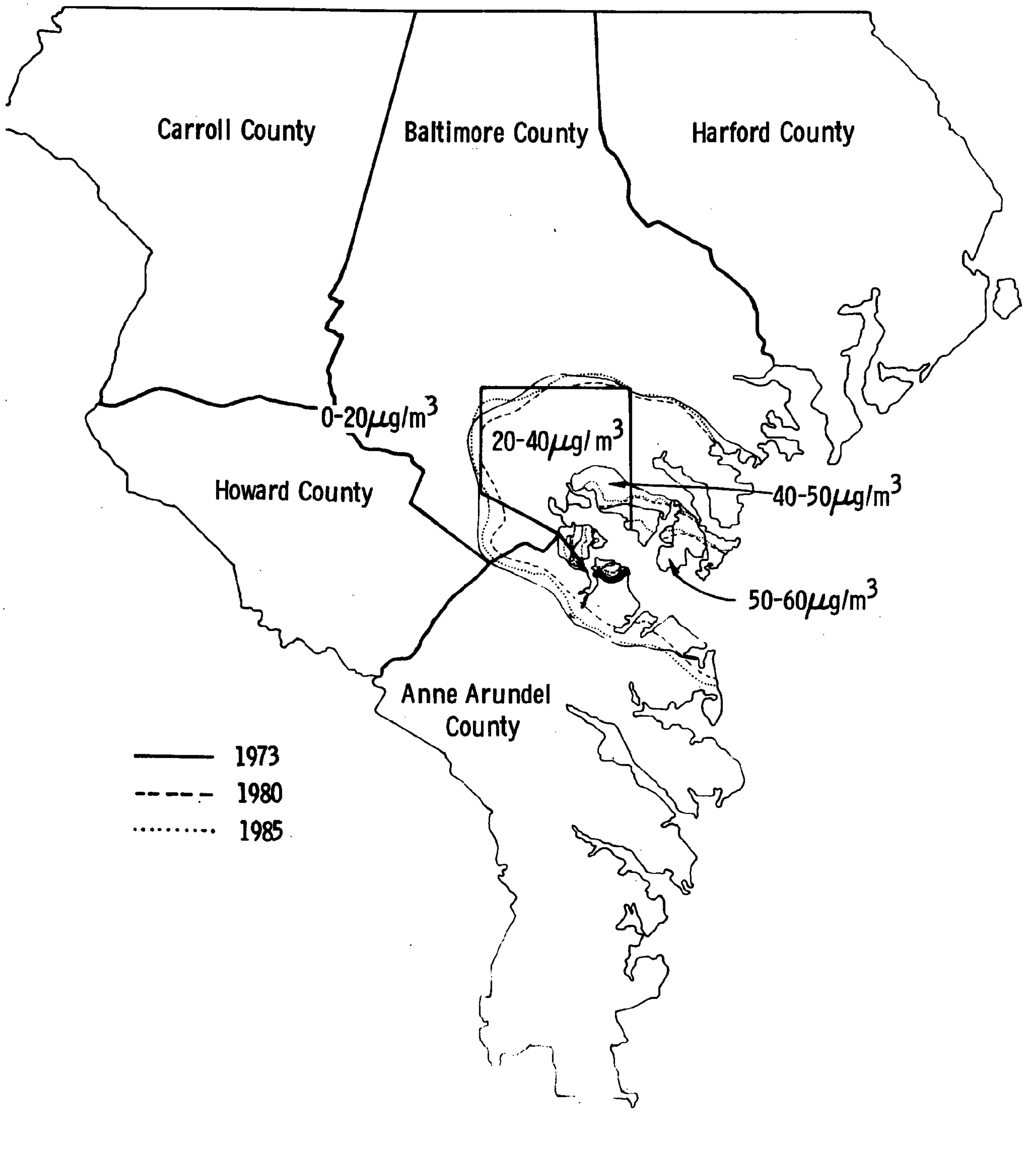

Figure II-10. Estimates of SO_2 ground-level concentrations by the Maryland Bureau of Air Quality and Noise Control

Table II-4. Calculate contribution to SO_2 ground-level concentrations from BG&E power plants compared to contributions from 23 other industrial sources at various receptor points in greater Baltimore.

Receptor Point	Percentage Contribution from BG&E Plants[a]	Percentage Contribution from other named Pollution Sources[b]
	1973 Conditions	
Sun and Chesapeake	15	73
Fort McHenry	18	70
Patapsco Sewage Treatment Plant	12	79
Reed Street	21	75
Essex	18	69
Sollers Point	12	79
Riviera Beach	27	64
Fort Howard	14	79
Sparrows Point High School	17	76
Sandy Plains	18	70
Cleaners Hangers	13	70
Fire Department #22	15	70

(a) The plants are: Crane, Riverside, Westport, Gould and Wagner. Calculations are rounded to nearest percentage point. These plants emitted 71,300 tons SO_2 in 1973.

(b) A total of 23 individual sources, which emitted 40,800 tons SO_2 in 1973.

calculations, since the total contributions shown in Table II-4 from the named sources adds up to about 90 percent of the GLC.

Nitrogen Oxides (NO_x)

Nitrogen oxides are formed in the power plant combustion process primarily by interaction of atmospheric nitrogen and oxygen at high temperature. There has been a national trend toward increasing ground-level concentrations of both nitric oxide (NO) and nitrogen dioxide (NO_2). Historical data for these pollutants is extremely limited. The Federal Continuous Air Monitoring Program (CAMP) shows increases of 13, 6, and 9 percent in NO, NO_2, and total NO + NO_2 ground-level concentrations, respectively, for the period 1964 to 1971 at the five urban CAMP sites (14).

The NO_x emissions from both power plants and motor vehicles have shown an increasing trend, but since 1976 the emissions from motor vehicles have stabilized because the increase in miles travelled has been offset be decreased emissions due to automotive pollution control devices (18).

Figure II-11 shows the trends in Maryland for the annual average ground-level concentration of NO_2 (12). It is difficult to separate power plant contributions from those of other sources.

Other Pollutants

Particulate Constituents. There are national and state standards for suspended particulate matter and state standards for settleable particulate matter. Because particulates are known to cause disease and discomfort, several constituents of particulates are being monitored, although there are no specific standards for their concentration level. One group of such constituents is the benzene soluable organic (BSO) portion (about 3 to 5 percent) of total suspended particulate matter in the ambient air. Polycyclic aromatic hydrocarbons, many of which are present in the BSO fraction, have been linked to cancer in animals, and one of them, Benzo-a-pyrene (BaP), is believed to be potentially carcinogenic in humans (19,20).

Power plants have relatively low hydrocarbon emissions because of their efficient combustion process, and the main sources of BSO are probably burning coal for space heating. A decrease of 50 percent of this activity from 1960 to 1970 (see Figure II-12) was probably the major reason for the declining trend in BSO and BaP (20). Controls on automotive combustion may be another factor. Since power plant coal consumption doubled from 1960-70 (Figure II-12) while the BSO level decreased, it is evident that power plants must have a minor effect on urban BSO levels. A definite seasonality in the BSO ground-level concentrations is also evident.

Sulfates. The sulfur emitted into the atmosphere is ultimately removed primarily by precipitation and dry deposition on the ground. Most of the SO_2 is converted to sulfate, either before or during this removal process. Global mass balance estimtaes yield atmospheric residence time for sulfur compounds in the range of 1 to 8 days, suggesting that long-range transport of sulfate is

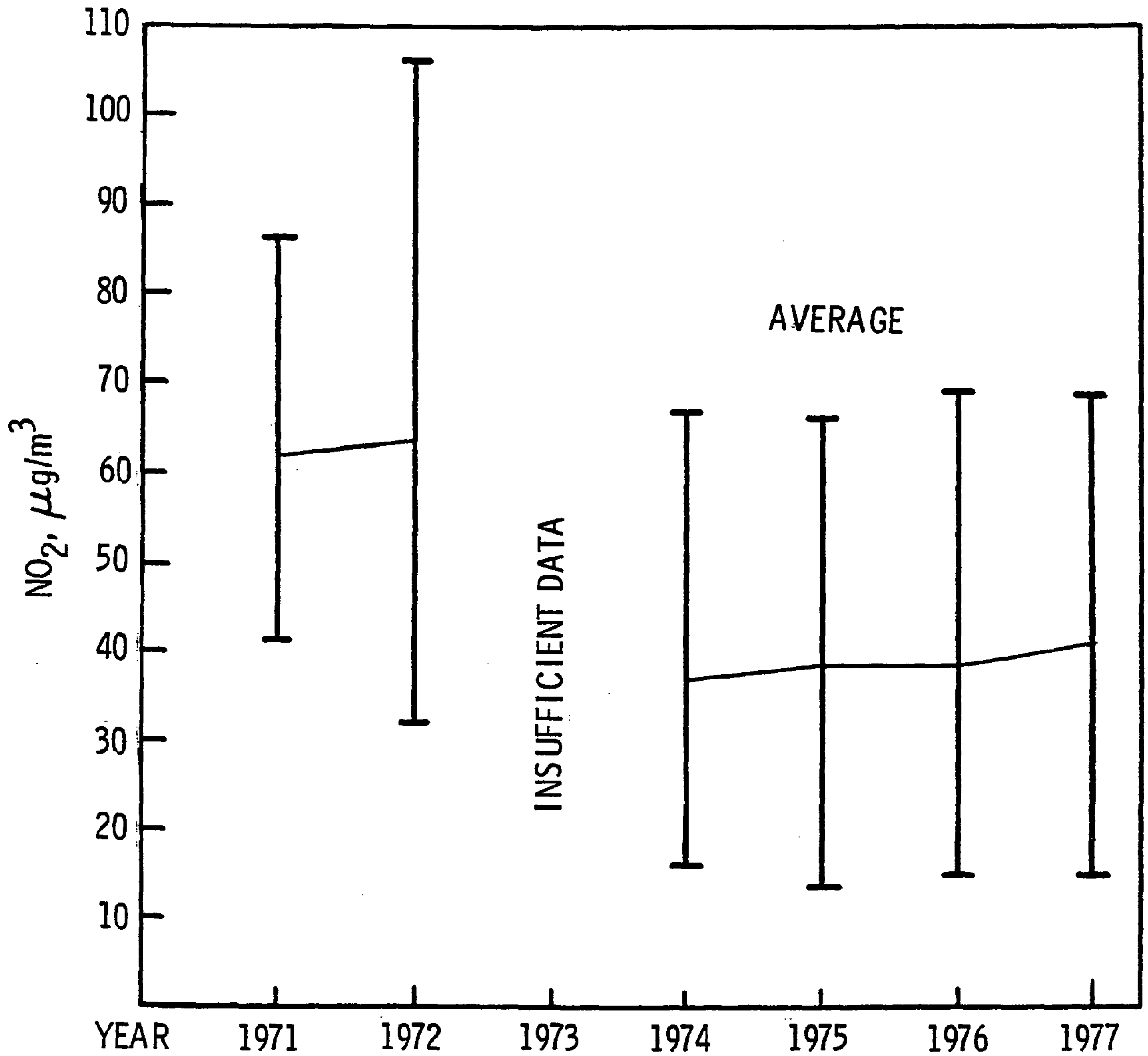

Figure II-11. Composite mean of annual arithmetic averages of NO_2 concentrations (measured by 24-hr gas bubbler) for Maryland since 1971. Ranges of values are indicated by the bars.

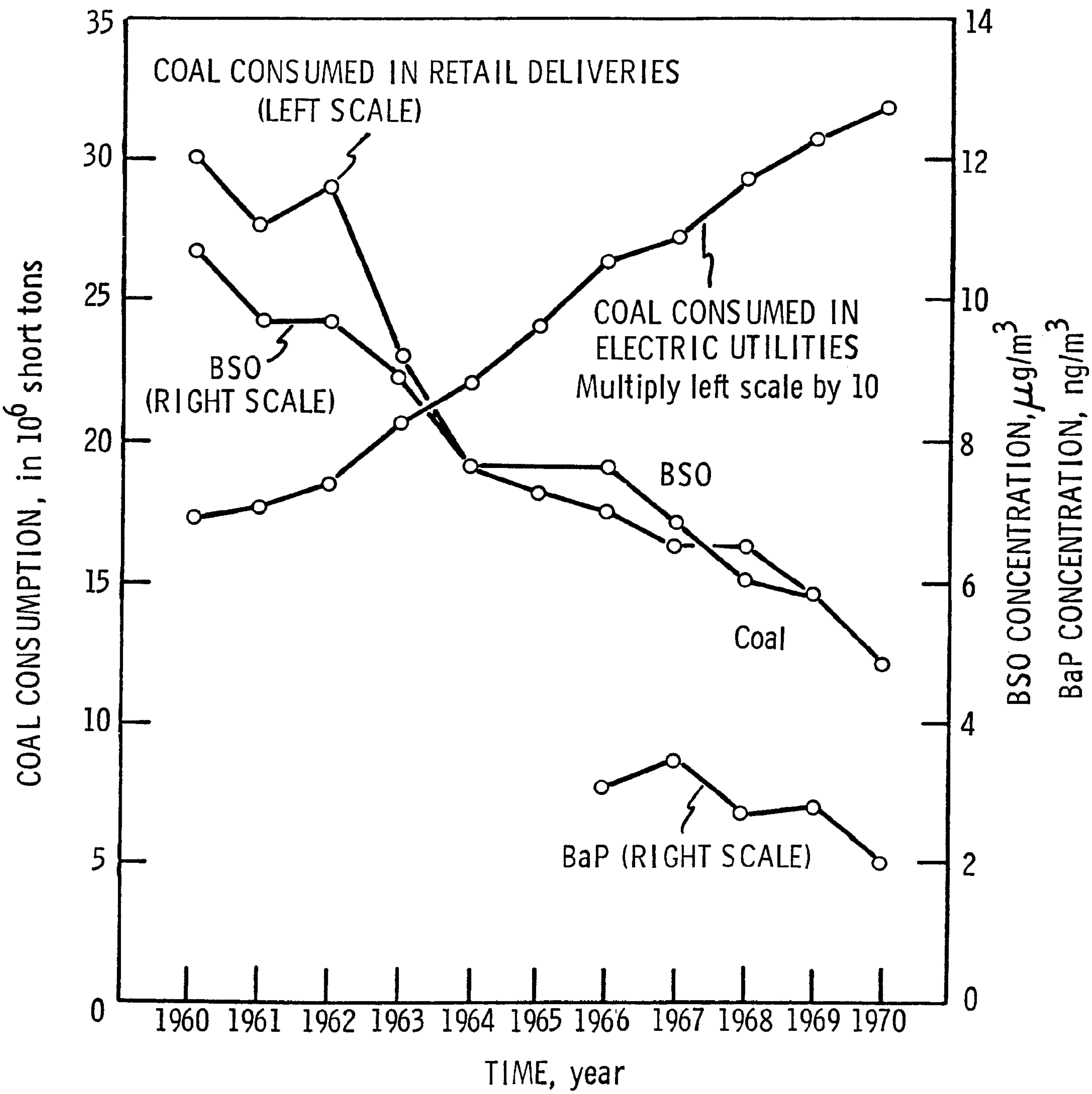

Figure II-12. Trends in national power plant and retail coal consumption, and in BSO and BAP annual averages. Utility coal consumption annual cumulative growth rate is approximately 7.2 percent from 1961 to 1971.

possible (21). A major concern is the possibility of long-range transport from the industrialized midwest into Maryland.

The various mechanisms for sulfate formation are poorly understood. The oxidation of SO_2 and its ultimate transformation into sulfates involve several reactive agents, such as fine particulates, ammonia, catalytic metals, and photochemical reactants. Sulfate formation rates are usually enhanced by high humidity and temperature. Rates of SO_2 oxidation in the ambient air are thought to range between 0.035 and 11.7 percent per minute (22).

It has been observed that SO_2 oxidation rates in power plant plumes for distances of up to 30 miles are 1 to 2 percent per hour for coal-fired plants and 10 to 20 percent per hour for oil-fired plants (23). This difference is explained as follows. In oil-fired plants, more metallic catalysts (e.g., vanadium) are present and accelerate the oxidation. Additionally, in the coal-produced plumes, SO_2 oxidation is originally inhibited by high concentrations of NO (nitric oxide), which will be preferentially oxidized to NO_2 by background oxidants. However, as the plume progresses downwind, several other factors enter into the oxidation process: NO is depleted as more ambient oxidants are encountered, NO_2 participates in a photochemical process leading to oxidation of SO_2, and ammonia (possibly of rural origin) in the ambient air acts to control one of the more important conversion mechanisms. Thus, the extent of SO_2 oxidation can depend more on concentrations of other precursors than on the concentration of SO_2 itself. Therefore, a reduction in ambient SO_2 level may not always produce a corresponding decrease in sulfate production, if these precursors are limited (24).

Nationwide, there has been a general decrease in urban SO_2 levels of more than 50% between 1960 and 1970, but there is no consistent trend for urban sulfates (14). A combination of long-range transport and the complex precursor relationship may account for this. The decreased SO_2 emissions in the cities reduce the local sulfate component, whereas the increased rural emissions, mostly from power plants, may have caused an influx of transported sulfates off-setting the decrease in the locally formed sulfates. Figure II-13 shown a comparison of Maryland quarterly averages of SO_2 and sulfates from 1976, when the sulfate measurements began (12).

Although there is mounting evidence of health hazards, no sulfate ground-level concentration standards have been established. EPA's current position is that not enough is known about sulfate formation and its health effects to warrant immediate establishment of standards (25). While standards are being formulated, control of sulfates will be attempted through maintenance of control of the precursor pollutants: SO_2 and particulates. Enforcement of state implementation plans for control of SO_2 and particulates, and increasing application of new source performance standards to power plants are thus relied on to reduce the rate of increase in the ambient sulfate levels.

<u>Photochemical Oxidants and Hydrocarbons.</u> Photochemical oxidants, mainly ozone (O_3), are pollutants of increasing concern. The mechanism of ozone formation in the atmosphere is not completely understood. There is complex relationship between precursor pollutants, particularly non-methane hydrocarbons (NMHC) and NO_x, possibly transported over considerable distances, and the creation of O_3 (26). In this respect, the situation is analogous to the SO_2-sulfate

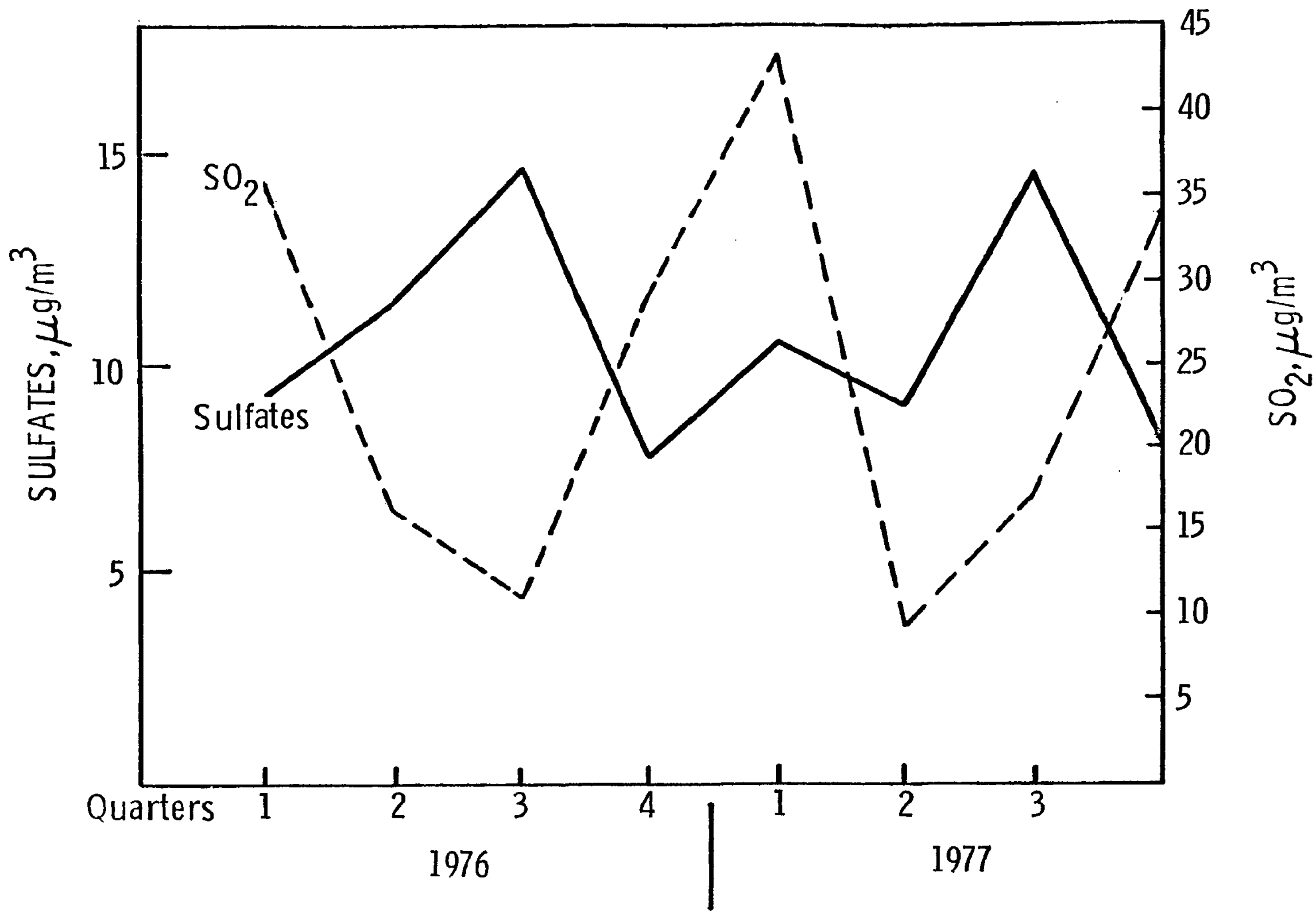

Figure II-13. Composite quarterly means of sulfate ground-level concentration since first quarter of 1976 when measurements began in Maryland. Also shown is the composite means of SO_2 for all stations using the flame photometric method.

relationship. Ambient air quality standards exist for both photochemical oxidants (measured as ozone) and hydrocarbons. The hydrocarbon standards are not based on any direct adverse effect of hydrocarbons, but rather on an empirical relationship, based on measurements, between hydrocarbon concentrations in the morning (the 3 hour period from 6 am to 9 am EST is the determining period in the Maryland Standards) and oxidant concentration occurring later during the same day. The hydrocarbon standard is designed primarily to achieve the standard for photochemical oxidants. In view of the lack of an exact quantitative relationship between the two constituents, and because hydrocarbons are difficult to identify and measure, the levels specified for hydrocarbons should be considered as guidelines only.* The standards are therefore not enforced. Both the oxidant and the hydrocarbon standards are consistently violated throughout the U.S., and Maryland is no exception. EPA is presently in the process of formulating a policy for control of photochemical oxidants. One of the major concerns is ozone formation in rural areas, caused by heavy influx of hydrocarbons transported from large population centers. Since a 1000 MW power plant typically emits 250 tons of non-methane hydrocarbons per year, any regulation of hydrocarbon could have a significant impact on power plant siting (see also Section G).**

E. Pollution Control

Ambient air quality can be improved by reducing emissions of pollutants from power plants (via emission control, conservation, cleaner fuel, or switching to alternatives such as solar or nuclear) or by enhancing dispersion. At present, emission controls are necessary for fossil-fueled power plants.

The need for emission control can be assessed by comparing emission factors to allowable emissions under the new source performance standards (NSPS). Table II-5 relates the new source performance standards to the emissions resulting from burning coal, oil, or gas without any emission control. Although it appears from the table that the new source performance standards for NO_2 cannot be met without additional emission control for any of the three fuels, it is possible to control combustion in a modern power plant boiler so that the NO_2 standard can be met.

Table II-5 shows that natural gas is the only fuel for which particulate emission control is not needed in order to comply with NSPS. For coal with an ash content of 15 percent, precipitators with an efficiency of about 99.7 percent would be necessary for plants using this fuel. Modern precipitator technology has progressed to the point where efficiencies exceeding 99 percent can be obtained (29), however, these efficiencies are often critically dependent on fly ash composition and sulfur content and must be carefully monitored.

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* There is considerable dispute on the ability of hydrocarbon control alone to reduce photochemical oxidant levels (27).

** Based on EPA emission factors (13). These factors are now under revision and may be reduced significantly (28).

Table II-5. Comparison of new source performance standards (NSPS) for emissions (in pounds per million BTU) and emission factors (in the same units) for combustion in utility boilers

POLLUTANT	PARTICULATE MATTER			SULFUR DIOXIDE			NITROGEN DIOXIDE		
FOSSIL FUEL AND FURNACE TYPE	STANDARD Old	STANDARD New	EMISSION FACTOR	STANDARD Old	STANDARD New*	EMISSION FACTOR	STANDARD Old	STANDARD New	EMISSION FACTOR
Coal	0.10	0.03		1.2	1.2		0.70	0.60 (0.50)	
Pulverized:									
general			0.67A			1.58S			0.75
wet bottom			0.54A						1.25
dry bottom			0.71A						0.75
cyclone			0.08A						2.29
Fuel Oil	0.10	0.03		0.80	0.80		0.30	0.30	
Tangentially fired			0.055			1.08S			0.34
Other									0.72
Natural Gas	0.10	0.03		No std.	0.80		0.20	0.20	
Tangentially fired			0.014			0.00055			0.27
Other									0.64

Note: The old standards did not apply to lignite. The new NO_x coal standard of 0.60 applies to bituminous coal, and 0.50 applies to subbituminous coal, shald oil, or any solid, liquid, or gaseous fuel derived from coal. There is no SO_2 NSPS for natural gas. A is ash content of coal in percent by weight. S is sulfur content in percent by weight.

Emission factors have been converted from the weight and volume units to BTU's using the following conversion, which approximates Maryland conditions:

Coal: 12,000 BTU/lb = 24×10^6 BTU/ton
Oil : 145,000 BTU/gal = 145×10^6 BTU/thousand gals
Gas : 1,100 BTU/cu ft = $1,100 \times 10^6$ BTU/million cu ft

Emission factors are only approximate guidelines and may be on the conservative (high) side. The emission factor of 1.58S for sulfur dioxide assumes that 95 percent (by weight) of the sulfur in the coal is released as sulfur dioxide.

* The new NSPS also requires a reduction (presumably by scrubbing) by 85 percent of the uncontrolled SO_2 emissions from solid, liquid, and gaseous fuel.

The old (1971) NSPS could be met through use of clean (or cleaned) fuels. For example control of SO_2 emission was not needed for gas. Oil could meet the emission standards, provided that the sulfur content was about 0.8 percent or lower. Attainment on this level presents no technical problem, although there may be a related economic penalty (see Table II-7). SO_2 emission control for coal-burning power plants could potentially be met by:

- use of coal of inherently low sulfur content (< 0.8 percent)
- cleaning of coal
- conversion of coal to cleaner fuels
- advanced combustion systems (fluidized bed combustion)

Extensive research programs funded by private and public interests, are underway in these areas as discussed below. The requirement of the new (1978) NSPS that all power plant effluents must be scrubbed for SO_2 reduction may remove much of the economic incentive for development of these technologies, although credit for pre-cleaning of the fuel will be given in the form of an easing of the SO_2 percent reduction requirements. The technologies discussed below will probably be commercially available for power plant operations in the 80's (30). Many of these technologies are not complicated for some small scale uses but are difficult to transfer to the scale of power plant fuel consumption and large volume of effluents.*

Use of Low Sulfur Coal

Table II-6a shows the estimated measured and indicated reserves of coal by sulfur content (18,31). Although reserves of Eastern and Western coal are roughly equal, it is seen that the preponderance (86 percent) of the "clean" coal (S < 1 percent) is in the West. In the East (Table II-6b) the preponderance of this clean coal is in West Virginia (53 percent) compared to Maryland's share (0.6 percent).

Coal demand by U.S. utilities by 1980 is projected to be about 620 million tons (32), of which about one half will have a sulfur content low enough to comply with the NSPS of 1.2 lb SO_2 emission per million BTU. This compares to a 1974 consumption of 390 million tons, again with one half conforming to the current new source emission regulations. Availability of low sulfur coal, and the desirability of using it for burning in power plants, depend on several economic and energy-policy considerations. The price differential between low-sulfur and high-sulfur coal in the Washington area in 1975 is shown in Table II-7 (32). A change in demand and point of origin of the coal can shift these costs considerably. The capital cost of converting a plant from high-sulfur to low-sulfur coal also varies considerably. One recent estimate is $20 per kW, which

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* A high efficiency 500 MW unit burns about 190 tons of coal per hour, 1.3×10^6 tons per year at 80% utilization, and will exhaust 1.16×10^6 cubic feet of air per minute (at 20% excess air), assuming 38 percent efficiency (9,000 BTU/kWh) and 12,000 BTU/lb.

Table II-6a. Estimated in-place coal reserves in millions short tons

Sulfur Content in % S by Weight	S < 1	1 < S < 3	3 < S	Unknown	TOTAL
Eastern States					
Deep Mine Reserves	21,200	48,461	65,992	25,811	161,464
Strip Mine Reserves	5,302	6,822	15,434	4,936	32,494
TOTAL	26,502	55,283	81,426	30,747	193,958
Percent of Regional Total	13.7	28.5	42.0	15.8	
Percent of U.S. Total	6.2	12.9	19.0	7.2	
Western States					
Deep Mine Reserves	99,457	10,757	7,727	13,216	131,157
Strip Mine Reserves	67,866	26,774	3,516	5,106	103,262
TOTAL	167,323	37,531	11,243	18,322	234,419
Percent of Regional Total	71.4	16.0	4.8	7.8	
Percent of U.S. Total	39.0	8.8	2.6	4.3	

Table II-6b. Estimated in-place coal reserves in millions short tons for eastern states with major reserves.

Sulfur Content % S	<1	1<S<3	3<S	Unknown	Total
Maryland					
Deep Mine	106	624	171	0	902*
Strip Mine	29	67	16	35	146
Pa., Ky., Va., W. Va.					
Deep Mine	18,787	32,319	17,571	12,086	78,186
Strip Mine	4,988	3,466	2,608	3,265	14,336
Other Eastern States					
Deep Mine	2,327	15,518	48,250	13,726	82,428
Strip Mine	285	3,289	12,810	1,637	18,029
TOTAL					
Deep	21,220	48,461	65,992	25,812	161,516
Strip	5,302	6,822	15,434	4,937	32,511

* The Maryland Geological Survey estimates 855 million tons recoverable in Maryland of which an estimated 100 million tons could be recovered by surface mining techniques. Maryland production in 1975 was about 2.5 million tons. Peak production (1907) was about 5.5 million tons. Conventional underground mining allows recovery of 50-60 percent of coal in place.

Table II-7. Energy costs in the Washington, D.C. area (1975 prices)

Residual Oil		
Percentage Sulfur	Cost per Barrel	Differential
.5 - 1.0	$ 13.10	---
1.0 - 2.0	$ 12.25	$ .85
2.0 - 2.8	$ 11.25	$ 1.85
> 2.8	$ 10.25	$ 2.85

Utility Steam Coal		
Percentage Sulfur	Cost per Ton	Differential
.5 - 1.0	$ 42.00	---
1.0 - 2.5	$ 35.00	$ 7.00
> 2.5	$ 30.00	$ 12.00

includes coal handling, combustion system modifications and the necessary changes in the particle emission control system (30).*

Another factor of importance is that much of the low sulfur coal found in the west has an appreciably lower heat value than the Eastern coal. Heat values as low as 7,500 BTU/lb commonly occur, compared to 12,000 BTU/lb (independent of sulfur content) for Eastern coal. Thus, the advantage of low emission from western low-sulfur coal is offset by the fact that more coal must be burned to get the same electric output. Transportation charges may also make use of Western coal unattractive. It is, therefore, not evident that use of low sulfur coal would be cost-competitive with other pollution reduction methods (see also Table II-10).

Cleaning of Coal

Sulfur is either chemically bound to hydrocarbon constituents of the coal (organic) or occurs in minerals (pyrite) associated with the coal (inorganic). Some of the sulfur can be removed from the coal, either by mechanical or chemical cleaning.

In the mechanical cleaning process (33), the coal is crushed and the inorganic impurities are removed by screening and washing, based on the difference in specific gravity between coal (about 1.3) and the pyrite (about 5.0). The organic sulfur cannot be removed by this process.

In Appalachian coal, pyritic sulfur can be as much as 40-80 percent of the total sulfur. Up to 80 percent of the pyrite can be removed by physical cleaning, leaving about 50 percent of the total sulfur (see Figure II-14). Since this coal often has a sulfur content of 2.5 to 3 percent, it can therefore not be reduced below the level required to meet the NSPS without additional emission control. Because coal with inherently low sulfur content contains most of its sulfur in organic form, physical cleaning does not work (see last three cases in Figure II-14). Concurrent benefits from the cleaning operation are increases in heat value** (from 12,000 BTU/lb to 13,400 BTU/lb), and removal of approximately one half of the ash content.

Washing of coal is done routinely, although percentages of coal cleaned has decreased from about 65 percent (332 million tons) in 1965 to 49 percent (289 million tons) in 1973 (32). Cost of mechanical cleaning (ranging from $2.50 to 4.00 per ton) has increased by a factor of four to five since 1968, mainly because of new government regulations of air and water pollution (32). Capital cost for a coal cleaning facility, including cost of environmental controls, may typically be the equivalent of an additional $12/kW in power plant capital cost. Additional costs may be incurred to upgrade power plant electrostatic precipitators. Operating cost is in the range of $0.10 to $0.20 per million BTU (corresponding to 1-2 mills per kW hr) (30).

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* Changes in fuel characteristics often necessitate changes in the emission control systems.

** Some coal is also removed in the cleaning processes so that there is a loss in the basic resource although the energy content per unit coal as burned has increased.

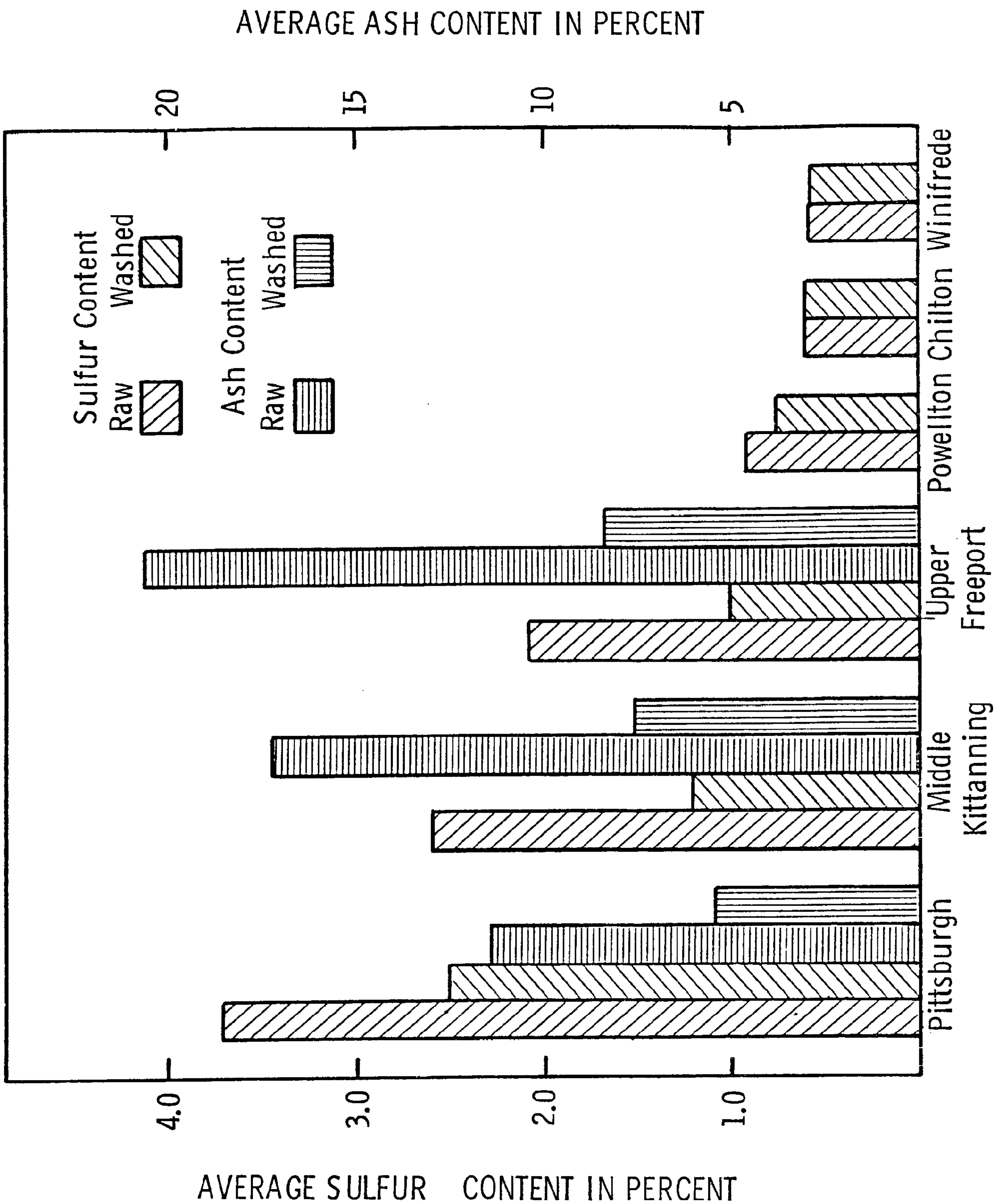

Figure II-14. Washability of some West Virginia coals. From U.S. Bureau of Mines test at 3/8 inch x 0 size and 80 percent yield. Note small reduction in sulfur content for the coals with low inherent sulfur content (last three coal beds).

Chemical cleaning of coal consists of grinding the coal into fine particles, which are treated with a reagent under controlled conditions of pressure and temperature. Both inorganic and organically bound sulfur can be removed by this process. The removal efficiency depends on a number of physical and chemical properties of the process and the coal. The technology is not commercially available, but is being pursued as an EPA development program (34). Chemical coal cleaning will probably be expensive and not available until the 1980's (see Table II-10).

Conversion by Coal Gasification

There are several ways of producing gas from coal (34,35). Generally, the coal is crushed and screened before being subjected to high temperatures (1,000 to 3,000 °F) and pressures (atmospheric to 1,000 psi). The end product of the various processes usually fall into one of the following categories:

- low BTU gas, heat values 100-200 BTU/cu ft
- medium BTU gas, heat values 300-500 BTU/cu ft
- high BTU pipe line quality, synthetic natural gas (SNG), heat value around 1000 BTU/cu ft.

Coal gasification technology for power plants probably can not be developed until the middle 80's, although numerous small systems are in operation around the world. The economics of coal gasification have been studied extensively (30,35). Although great uncertainty exists in the projections, it now seems that these systems will not be cost-effective in comparison to other available fuel and control options (see Table II-10).

Conversion by Coal Liquefication

Liquid fuels can be prepared from coal by several different processes. For power plant applications, several processes that hydrogenate coal to a liquid have shown promise (34,35).

Commercial application of coal liquefication for power plant use is possible by the mid 1980's. Cost estimates are uncertain, but it appears that costs will be high, and the technique will probably not be competitive with the other techniques shown in Table II-10.

Fluidized Bed Combustion

In a fluidized bed combustion system, a grid or distribution plate at the bottom of the boiler supports a mixed bed of granular limestone or dolomite and pulverized coal (36,37,38). High velocity combustion air (2-5 fps) is blown up through the bed suspending or fluidizing it. Because of the thorough mixing and large contact area of fuel and air throughout the bed, an evenly distributed, complete combustion can be supported at a lower temperature than in a conventional boiler. The heat generated in the bed can be removed by heat exchanger directly in the bed as well as in the heated gas flow.

Most of the SO_2 produced by the combustion is removed by reaction with the limestone or the dolomite in the bed. The limestone or dolomite cn be regenerated for repeated use in the boiler. The advantages of the fluidized bed system over conventional boilers include:

- high heat release rates and transfer rates in the bed which
  - -- allow lower temperatures to be used (e.g., 1550-1750° F) than in a conventional boiler (e.g., 2700° F) resulting in lower NO_x emissions
  - -- allow boiler size to be reduced by as much as 50% resulting in lower construction cost
- removal of SO_2 directly at the combustion source.

Sulfur removal efficiencies of 90-95 percent have been measured on experimental units using a limestone or dolomite sorbent. Nitrogen oxides are generally emitted at levels of 0.3-0.6 lb/million BTU, well below the NSPS of 0.7 lb/million BTU. Particulate emissions can be high for fluidized bed systems, and are very sensitive to bed operating conditions.

Fluidized beds can be operated at atmospheric pressure or pressurized. In a pressurized system, a gas turbine cycle can be combined with the steam turbine cycle, with possible operating efficiencies in the 40% range. The feasibility of this system depends on adequate removal of particulates upstream from the gas turbine.

Atmospheric pressure fluidized bed coal combustion systems for large power plants will probably be operational in the mid 1980's and may well prove to be less expensive than current combustion technology (Table II-10).

Flue Gas Desulfurization (FGD)

Engineering development of flue gas desulfurization systems (scrubbers) will probably receive a major impetus from the NSPS requirement for SO_2 reduction of the uncontrolled emissions. FGD systems use a sorbent, usually lime (CaO) or limestone ($CaCO_3$) to absorb or react with the SO_2 (39,40,41,42). The sorbent can be discarded after the use or regenerated for repeated use. The most common FGD systems are non-regenerable. The resulting sludge (consisting of a mixture of fly ash, calcium sulfite, calcium sulfate, and water) must be disposed of either in settling ponds or (if treated with a fixative) in a landfill tract. This disposal can be a significant environmental problem.

A typical 1000 MW plant, burning 3.5 percent sulfur coal with 12 percent ash content (as fired) with a lime scrubber removing 90 percent of the SO_2 will generate about 200 tons of settleable slurry and ash per hour, 60 percent of which is calcium solids. The settled material (slurry and ash) has a specific gravity of 1.31 (with 60 percent water content), so that the volume created is about 140 m^3/hr. For a lifetime of plant operation, assumed to be 127,500 hrs, this amounts to a volume of 1.77 x $10^7 m^3$, or a settling pond 40 feet deep with an area of about 360 acres. Implicit assumptions in this calculation are: 75 percent of ash content becomes fly ash, 99.5 percent of particulates are removed in the precipitator, heat rate 9000 BTU/kWh, heat value of coal 12,000 BTU/lb, giving coal consumption of 375 tons/hr. For a limestone system, the calcium solids are 15 to 20 percent more than for the lime system (43).

The most important regenerable systems are the magnesium oxide (MagOx) and the Wellman-Lord sodium sulfite process. In a regenerable system, the sulfur is removed from the sludge (or liquid in certain processes) and converted to a marketable product such as sulfuric acid or elemental sulfur. The sorbent medium is reused. The 1000 MW plant described above will generate about 775 tons of 98 percent sulfuric acid per day using the Magnesium Oxide process. In the sodium sulfite processes about 275 tons of sulfur is generated per day, and about 90 tons of sodium sulfate. About 5500 tons of particulate slurry (15 percent undissolved solids) representing the ash, will also have to be disposed of per day. The catalytic oxidation process will generate about 950 tons of 80 percent sulfuric acid (about 800 tons of dry ash will have to be disposed of per day) (43).

There has been a great deal of controversy over whether SO_2 scrubbers are reliable, and whether or not they constitute "available technology" as opposed to "experimental technology." According to the National Academy of Engineering, FGD can be considered "available technology" if it can operate continuously for one year with no more than 10 percent down time. Most of the early problems with FGD systems are being solved to provide acceptable reliability and efficiency at the high temperatures and large flow volumes of large steam electric plants. However, while the terms of the NAE's definition are increasingly being met the controversy continues.

The status of FGD systems is shown in Table II-8 (44). There are 139 systems in operation, under construction, or planned as of July 1978, representing close to 60,000 MW of generating capacity (total fossil-fueled generating capacity of all private and public utilities was about 532,000 MW in 1978) of which 250,000 MW, or 47 percent is coal-fired. Scrubber systems are installed on about 6 percent of present coal-fired capacity. The SO_2 removal efficiency is generally in the 80-90 percent range, and reliability of the more recent installations approximates 90 percent (44).

Table II-9 shows the various processes selected as of 1978, and a projection to 1986. It can be seen that the preferred system is, and will continue to be, limestone. Non-regenerable lime and limestone systems constituted 96 percent of FGD systems installed in new plants and 83 percent of FGD systems retrofitted into old plants (44). About 80 percent of present installations are on new power plants (the remainder are retrofits), and by 1986 the percentage of new installations will increase to 84 percent. Present projections (44) indicate that by the end of 1986, 16 percent of the coal-fired capacity will be controlled by FGD. This situation could be changed if the 85 percent scrubbing requirement is retained in the New Source Performance Standards.

The cost of SO_2 control technologies have been studied extensively (43, 45,46). Costs to be considered are not only capital costs and operational costs in the conventional sense, but also costs associated with the environmental impacts each one of the methods will create. As discussed above, for non-regenerable scrubbers, there will be waste disposal problems; for regenerable scrubbers, some waste disposal may be necessary; for coal processing, there may be problems of water availability and pollution. Disposal of solid waste, such as fly-ash and sludge will be covered by regulations to be

Table II-8. Status of SO_2 scrubber system applications as of July, 1978

Status	Number of Units	MW Capacity
Operational	40	14,440
Under Construction	42	16,834
Planned:		
Contract Awarded	21	10,708
Letter of Intent	3	1,960
Requesting/Evaluating Bid	4	2,255
Considering only FGD systems	29	13,232
TOTAL	139	59,429

Table II-9. SO_2 scrubber system selection in terms of MW capacity

Process	Total MW of Installations	
	1978	1986
Lime	6,070	15,581
Limestone	7,426	26,766
Lime/Limestone	20	680
Magox	120	846
Wellman-Lord	429	1,855
Others	375	2,546
Not Selected	---	11,155
TOTAL	14,440	59,429

Table II-10. Cost of SO_2 control technologies for baseload plants in 1975 dollars

		Basic Plant	Control Technology	Annualized Costs - mills/kWh		
		Capital Cost $/kW	Capital Cost $/kW	Coal	Control Technology	Total Power
Conventional Boiler						
Coal Fired:						
High Sulfur Coal (>2.5% S)	(TVA)	500 - 700	0	10.8	0	34.4
Medium Sulfur Coal (1-2.5% S)	(TVA)	510 - 710	0	12.6	0	36.5
Low Sulfur Coal (<1.2% S)	(TVA)	520 - 720	0	15.2	0	39.3
Low Sulfur Coal	(EPRI)	375 - 455	0	12.5		
	(ERDA)	294 - 404	0	13.0-15.0		
Physical Coal Cleaning	(TVA)		12.0	10.8	1.5	35.9
Chemical Coal Cleaning	(TVA)		75.0	10.8	4.5	38.9
Flue Gas Desulfurization:						
Lime/Limestone	(TVA)		48.9	10.8	3.3	37.7
	(EPRI)		110-170	10.0	6.0-7.5	
	(ERDA)		72.0	11.0-13.0	2.6-3.6	
Magnesium Oxide	(TVA)		57.4	10.8	2.6	36.0
Sodium Sulfite	(TVA)		67.8	10.8	4.0	38.4
Unspecified Regenerable	(EPRI)		185-280	10.0	7.0-9.5	
New Fuels:						
Coal Gasification w/Steam Turbine	(TVA)	500 - 655	-	10.8	6.8-7.6	41.3
	(EPRI)	760 - 1000 245 - 300	205-700*	10.0	0	
Coal Gasification w/Combined Cycle	(EPRI)	190 - 260	175-600*	8.0	0	
	(ERDA)	395 - 555	-	8.5	0	
Coal Liquefaction	(TVA)	N/A	-	-	-	N/A
	(EPRI)	375 - 500	-	10.0	-	
Fluidized Bed Boiler						
Atmospheric	(TVA)	632	-	10.8	-	32.9
	(EPRI)	450 - 655	-	10.0	-	
	(ERDA)	389 - 409	-	11.0-13.0	-	
Pressurized	(TVA)	723	-	10.8	-	38.4
	(ERDA)	332 - 462	-	11.0-13.0	-	

*Covers a range of low and medium BTU processes. TVA assumes 0.80 capacity factor; EPRI 0.65; ERDA variable over life of plant, average about 0.60.

Footnote to Table II-10

(a) Data labeled TVA has been adapted from (33) and adjusted to a high sulfur coal cost of \$30/ton and low sulfur coal cost of \$42/ton. Heat values assumed to be 12,500 BTU/lb and 9,025 BTU/kWh. The TVA data for flue gas desulfurization systems (scrubbers) are derived in (43). A base loaded plant of 500 MW capacity is assumed, with an operating life of 30 years over a declining operating profile (total of 127,500 hours). A 3 year construction schedule ending in mid-1975 is assumed at a mid-Western location. For the midpoint of construction the Chemical Engineering Cost Index is 160.2, inflation factor from 1975 to 1977 is about 1.2 (20 percent). Solid waste disposal costs assume conditions existing in 1975. Coal is assumed to have 12% ash content, oil is 18,500 BTU/lb with ash content of 0.1%. Additional cost assumptions, including recovered cost for by-product sales, are found in (43).

Only the TVA costs have been carried forward to total annualized costs in mills/kWh. EPRI and ERDA costs (48) are also 1975 costs. EPRI assumes capacity factor of 0.65 and coal cost of \$1/million BTU. ERDA has a variable capacity factor over the plant lifetime (average about 0.6) and coal cost varying between \$0.68 and \$0.92 per million BTU.

PEDCo Environmental, Inc. has recently (44) collected cost data for existing scrubber systems, and adjusted cost reported by utilities to a common July 1, 1977 basis incorporating the following:

- Capital cost based on gross capacity, annual expenditures on net.
- Particulate control costs deducted, but regeneration and by-product recovery facility costs included. Replacement power costs not included.
- Capital cost of modification or installation of equipment not part of the FGD system included if required for operation of the system.
- Indirect charges adjusted to provide for engineering, field expenses, legal services, insurance, interest during construction, allowance for start-up, taxes, and contingencies.
- Annual cost adjusted to 65% capacity factor.
- 30-year life for new systems, 20-year life for retrofits.
- Sludge disposal costs adjusted to include SO_2 waste disposal (not fly-ash) over the anticipated lifetime of the system.

Some of the results of this analysis are:

	Average Adjusted Costs	
	Capital, \$/kW	Annual, mills/kWh
All systems	95.8	5.53
New systems	87.6	5.13
Retrofit systems	103.4	5.92
Lime	94.1	7.03
Limestone	87.0	4.55

(b) Covers a range of low and medium BTU processes.

promulgated by EPA under authority of the Resource Conservation and Recovery Act of 1976 (RCRA). There are indications that EPA may designate fly-ash and scrubber sludge as hazardous wastes. If so, disposal cost could reach \$25 to \$30 per ton of fly ash or sludge (47). Cost recovery through sale of useful by-products from some of the processes also present an estimating uncertainty. Equipment maintenance problems present another area of uncertainty.

Although many scrubber systems are in full scale operation there is little solid cost experience to build on because so many of the installations involve retrofitting, with all its site specific conditions, or developmental installations, often with shared financing, which makes it difficult to assess true costs of installation and operation.

Table II-10 gives an overview of the effect of SO_2 control techniques on the cost of electric power. The values are developed from a number of sources (33,46,48) and provide a rough indication of relative costs. The absolute cost figures have considerable uncertainty attached to them and also depend on factors which are highly variable, such as fuel costs and transportation costs.

The current situation regarding SO_2 abatement can be summarized as follows: Choice of an SO_2 control strategy is complicated by the interaction of operational and economic factors, the availability of low sulfur fuel, the uncertainties associated with the new NSPS requirements for SO_2 scrubbing and the variability of emission regulations throughout the U.S. However, several conclusions can be drawn from the current knowledge of SO_2 emission control technology.

Using currently available technology, all coal-fired electric power plants in Maryland could operate in compliance with present State emission standards by 1985.

Between now and 1985, only about half of the projected national coal demand can be supplied with low sulfur coal. Therefore, SO_2 emission standards can only be achieved through a combination of low sulfur coal use, coal-cleaning, and FGD technology. The utilities in Maryland will reflect this mix in their plant design and operations.

In new installations there is no major economic penalty associated with FGD (as opposed to retrofits which are much more expensive). Cost of FGD starting with high sulfur coal is comparable to, or slightly below, the price of electricity using low sulfur coal, despite the large differential in capital costs.

F. Mathematical Modeling

Mathematical modeling is becoming increasingly important for air quality predictions and maintenance studies. Section 320 of the 1977 amendments to the Clean Air Act (49) recognizes modeling as a necessary tool, especially as it relates to the problems of prevention of significant deterioration (PSD) of air quality.

The Gaussian plume equation is currently the most widely used model (50). It is based on the idea that, over a short time, a plume of pollutants will tend to move with the wind in such a manner that the average density has a normal (i.e., Gaussian) distribution about the mean wind direction both in the lateral direction and in altitude. It is further assumed that the pollutant is conservative, i.e., that there is no loss of pollutant due to chemical reactions or ground deposition, and that the plume will be perfectly reflected from the ground.

Attractive features of the Gaussian plume model are its simplicity, and the fact that the required input parameters are readily measurable. More complex models for pollution dispersion, based on flow field analyses and solution of standard turbulent diffusion equations, have been developed (51). However, they require input data that are not readily available, and they do not, in general, give consistently better results than the simple Gaussian model.

In the Gaussian model the ground-level concentration (GLC) is directly proportional to the emission rate, which again is directly proportional to the sulfur level in the fuel and to the fraction of SO_2 not removed by the scrubber. Therefore, the data presented can easily be scaled to other values of sulfur content and scrubber efficiency through use of the factor

$$F = S\left(1 - \frac{\text{scrubber efficiency in percent}}{100}\right),$$

where S is the sulfur content of the fuel.

The general shape of the ground-level concentration along the plume centerline as a function of the downwind distance x is shown in Figure II-15. We can see that c, the GLC, is zero near the source, rises to a maximum, c_{max}, at a distance x_{max}, and then slowly decreases to zero as x increases (for large values of x the applicability of the model is in question, as will be discussed later). In general, c_{max} is inversely proportional to the emission rate Q which in turn is proportional to the power level and the F factor discussed above. As a general approximation, c_{max} is inversely proportional to the square of the effective stack height (h_e). The dependency on wind speed, v, is more complex since h_e also depends on wind speed. The effective stack height is also a function of the difference, ΔT, between stack gas temperature and the ambient temperature, in such a way that h_e decreases with decreasing ΔT. Therefore, a decrease in ΔT generally will result in an increase in c_{max}. Thus, it is conceivable that a flue gas scrubber, while removing SO_2 (i.e., reducing the emitted quantity of pollutants) may lower the flue gas exit temperature (and therefore the effective stack height) to the point where the GLC actually increases. This is a paradoxical situation, where removal of pollutants decreases the ambient air quality. These basic parametric relationships are important to the subsequent discussion of air modeling results as they apply to future siting decisions.

In view of its central position in air quality assessments, the limitations of the Gaussian pollutant dispersion model must also be understood. There is a limit to the distance over which the model can be applied with any degree of confidence even for flat terrain. Two basic factors must be considered:

- The calculations are usually based on meteorlogical conditions at a point at or near the emission source. It is unlikely that these conditions persist over an infinite range downwind of the source. Both wind direction and the state of the atmosphere with respect to

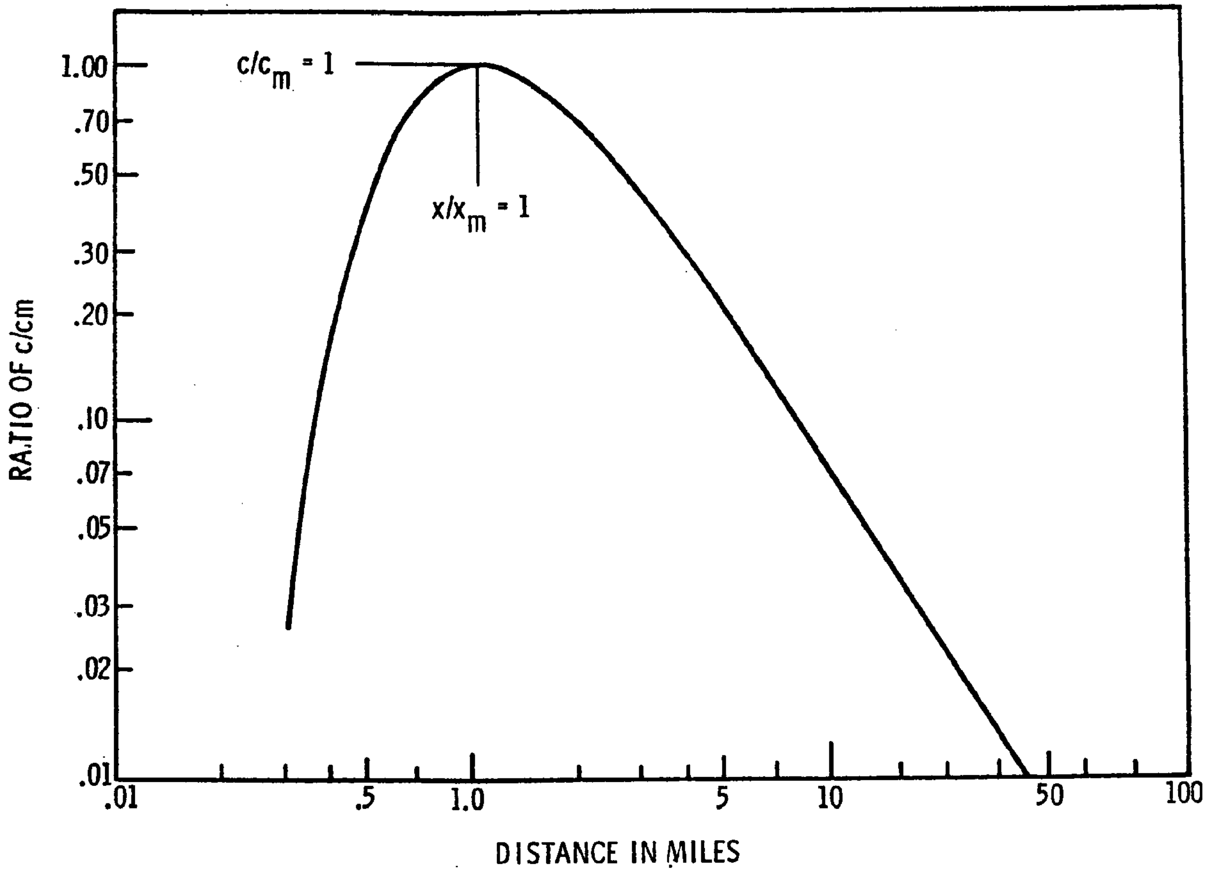

Figure II-15. Representation of the Gaussian plume equation.

$$c_{max} = \frac{Q\ \alpha^{\alpha/2}}{\pi v a_1 a_2} \frac{\exp\left(-\frac{\alpha}{2}\right)}{\left(h_2/a_2\right)^{\alpha}} \quad \text{when } \alpha = 1 + \frac{b_1}{b_2}$$

The a's and b's are coefficients determining the dispersion parameters

$$\sigma_y = a_1\ x^{b_1}$$

$$\sigma_z = a_2\ x^{b_2}$$

The graph has been normalized to present ratio of actual ground-level concentration c to the maximum c_m, as a function of actual distance x to the distance x_m at which the maximum concentration will occur. The numerical values apply to Brookhaven C stability class. Note logarithmic scales.

turbulence and other parameters affecting mixing will change. The functional form assumed for the dispersion parameters (σ's) can also not be expected to hold indefinitely for larger values of x.

- The assumption of a conservative pollutant does not hold ad infinitum because of dry ground deposition, wash-out, and chemical processes. This problem is currently under investigation and some of the conversion processes were discussed earlier in connection with the sulfate problem (p. II-24).

Other problems with the Gaussian plume dispersion model appear under certain meteorological conditions. These conditions include low wind speed, where the concept of a continuous plume is not valid and stable atmospheric conditions, where the "standard" dispersion coefficients to an elevated plume rising from a tall stack are not necessarily applicable.

There is also a problem in applying the Gaussian model in rough (non-flat) terrain where topographical features strongly affect the air flow. A number of Gaussian rough terrain models are in common use (51). Most of them are rather primitive, in the sense that they take the Gaussian plume and modify the effective height of the emitting source by some fraction of the height of the terrain at the point of plume impingement. This type of model generally does not agree with measured GLC, [e.g., Power Plant Siting Program studies at Luke, Maryland (52)].

The general Gaussian model has been tested extensively in the Maryland Power Plant Siting Program for three different power plants and for various algorithms for determining stability classes, dispersion parameters and plume rise. For flat terrain the best model was found to agree with measured concentrations to within a multiplicative factor of 2 in about 70 percent of the 126 cases that were tested (53).

The thrust of current development in the Siting Program is toward mathematical models that consider actual flow patterns. Flow patterns, air pressure distributions and velocity profiles are studied in wind tunnels simulating the existing meteorological and topographic conditions. It is expected that this ongoing work will lead to a better understanding and formulation of the underlying physical principles of dispersion. In practice, the influence of local features (i.e., local emissions, and local topography and meteorology) can create great differences between actual point measurements and model predictions.

Plume measurements have generally been confined to ground level. It is possible to make airborne measurements, but these are expensive and beset with practical problems such as helicopter rotor downwash interference and instrument time response problems from fixed wing aircraft. Improved measurement methods are expected to aid materially in future model development. The Power Plant Siting Program, in cooperation with NASA, has been using Lidar (a laser-type remote sensing instrument) for plume measurements (54). The Lidar is useful in studying details of plume rise (near the stack), vertical plume structure, and three dimensional development along the plume. The demonstrated capability of Lidar to track particulates is currently being extended to chemical pollutants such as SO_2 and photochemical oxidants.

G. Regulatory Effects

The Clean Air Act Amendments of 1977 are of major importance in that they give specific legislative direction to "prevention of significant deterioration," one of the most controversial concepts of air pollution control.

The amendments also give focus to other control approaches which have developed over the years since the previous amendment to the Clean Air Act was passed in 1970. Some of the most significant areas of importance to power plant siting and operation are discussed below.

Stack Height and Intermittent Control

One of the air pollutant control techniques proposed (and in some cases implemented) by electric utilities was the use of tall stacks, switching of fuel, and switching of load between plants in such a manner that the air shed impact, in the form of pollutant GLC was minimized.

EPA argued against the acceptability of this method on the ground that tall stacks and switching of load to other plants in a utility system did not diminish emissions, although a better air quality, as defined by GLC was attained by spreading the pollutants.

The new act essentially eliminates the use of these dispersion techniques by denying credit for pollution abatement by these techniques. In particular, credit is denied for stack height exceeding "good engineering practice," which is "the height necessary to insure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash eddies and wakes which may be created by the source itself, nearby structures or nearby terrain obstacles." (Section 123 of the Act) EPA has recently proposed a set of regulations pertaining to tall stacks (55). The height for good engineering practice is interpreted as the height of the structure plus 1.5 times the lesser height or width of the structure. "Nearby" is taken to be a distance up to 5 times the height or width of the structure, but not more than 0.5 miles (0.8 km) away unless a greater height is necessary to avoid the excessive concentrations referred to above.

The height of the source, i.e., the structure of a power plant, is typically such that stack height is limited to the 500 to 600 feet range. It is not clear at this time whether cooling towers (which range up to 450 feet tall) are to be included as source structures. If they are (and there are often good engineering reasons for including them), then the law provides no practical limitation upon stack heights. If they are not, then the stack height limitation may be important to meeting the prevention of significant deterioration criteria as will be discussed below.

Non-Attainment Areas

When an area exceeds Federal ambient air quality standards, it becomes a non-attainment area, and no further growth in pollutant emissions from major sources is allowed.* To permit new industries to locate in such regions, the EPA (under the Clean Air Act) has promulgated a policy of "emission offsets" (49). A new power plant, if it wishes to locate in such a region, must not only meet an emission limitation specified as the Lowest Achievable Emission Rate (LAER) for that source, but must also provide for sufficient reduction of emissions from other sources (its own or others) in the area to offset its new emissions, so that "reasonable progress toward attainment of the applicable NAAQS" is made.** Any power plant, outside the non-attainment region, producing a "significant" decrease in the air quality of the non-attainment region, is also subject to an offset requirement.

Although the idea behind this policy is to satisfy the competing needs of growth and maintenance of air quality, it entails several significant consequences. First, it appears to give industries now emitting major amounts of pollutants the power to sell "pollution rights." That is, they could sell the right to clean up their output levels to whomever they chose (or refuse to do so) for more than the price of the control equipment. In fact, it is possible for a company to be economically responsible for the operation and maintenance of another company's pollution controls. Another consequence is that the economic burden of controls, both for its own plant and the offset plants, would be borne by any new source (as opposed to the sources already located in the area). Thus, unless there are compelling economic considerations for locating in a particular region, power plants will tend to locate far enough away from non-attainment areas so that they will not be subject to an offset.

In Maryland there are presently four pollutants for which non-attainment areas exist: particulates and carbon monoxide (Baltimore and Western Maryland), hydrocarbons, and photochemical oxidants (Baltimore, Washington, and scattered areas elsewhere). Because of the differing sources and nature of these pollutants, different offset policies have been developed.

Any source increasing the concentration of particulates in a non-attainment area by more than 1.0 $\mu g/m^3$ (annual average) or 5.0 $\mu g/m^3$ (24 hour average) is subject to an offset (49). To estimate the implications of this policy for power plants, a typical 1000 MW coal-fired generating station emitting at the new source performance standards (Table II-3) was modeled for "worst-case" conditions. The results indicated that, to avoid an offset, such a plant would have to locate 10-15 miles from the border of a non-attainment area, depending upon the local meteorology.

Photochemical oxidants, because of the regional nature of their emissions and their slow reaction/deposition rates, have been approached from a larger geographic scale. According to a draft EPA policy (56) any major source

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* Although the present discussion will center on power plants, the conclusions will be valid for all large emission sources with similar characteristics.

** The applicant must also certify that all the existing major sources he owns or operates in the same state are in compliance with the applicable emission limitations or are meeting the target dates of a compliance schedule.

(greater than 50 tons/year) locating within an 85 mile circle of Baltimore or Washington would require an offset. When similar circles around Pittsburgh and Philadelphia are considered, most of the State (all except the tip of Garrett and Worcester Counties) is subject to an offset. In this case, the offset is not the for primary pollutant (O_3) but is for a percursor, non-methane hydrocarbons (NMHC). A typical 1000 MW generating station produces about 250 tons/year of NMHC.* The major difficulty in this offset policy is finding controllable stationary sources that can produce an offset. Table II-3, the State-wide total emissions inventory, shows that 77 percent of the NMHC emissions (in 1975) come from mobile sources (automobiles and trucks). When road resurfacing is added, the transportation sector produces 85-90 percent of the total emissions. Clearly, any strategy to control hydrocarbons should include this sector.

These policies are now being used to evaluate the proposed expansion at Sollers Point (100-600 NW of gas turbines). The proposed site is a non-attainment area for particulates, hydrocarbons, and photochemical oxidants. The preliminary site investigation (57) indicates that the plant will have to meet the offset requirements listed above. An output of six hundred megawatts, previously proposed by BG&E, has been ruled unsuitable by the Department of Natural Resources. A detailed site evaluation study now in preparation by Applied Physics Laboratory of Johns Hopkins University will more clearly define available options and requirements. In the 1978 Ten-Year Plan, BG&E listed a proposed installation of only 100 MW (58).

Thus, the existing non-attainment areas in Maryland will influence the siting of future fossil-fueled power plants either by requiring use of an offset or by requiring the plants to locate outside the affected region.

Prevention of Significant Deterioration (PSD)

The most significant change within the Clean Air Act relates to PSD (59,60). The law establishes upper limits on allowable air quality changes for SO_2 and particulates. It designates three classes of areas with differing restrictions on increases in pollution levels. The allowed increases (increments) for each area and the comparable standards are shown in Table II-11. The total increments caused by all users must stay within the specified limits.

The Class I area designation is reserved for regions where it is desirable to maintain the present air quality. Automatically classified within this category are international parks, national wilderness and memorial parks over 5000 acres in size, and national parks over 6000 acres in size. Other areas may be added to this list by the State, in some cases at the suggestion of the Federal Land Manager. Maryland has no Class I areas at this time,** although there are several such areas in nearby Virginia and West Virginia. Figure II-16 shows the mandatory and discretionary areas in and near Maryland that have been mentioned by Federal agencies for possible Class I designation.

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* Emission factor under revision by EPA (28).

** Fort McHenry has been proposed as a Class I area by the National Park Service.

Table II-11. Prevention of significant deterioration of air quality. Maximum allowable increase in ground-level concentration of particulate matter and sulfur dioxide under the provisions of the Clean Air Act Amendments of 1977*

Area Designation	Maximum Allowable Increases $\mu g/m^3$ Class I	Class II	Class III
Pollutant:			
Particulate Matter			
Annual Geometric Mean	5	19	37
24-hr Maximum	10	37	75
Sulfur Dioxide			
Annual Arithmetic Mean	2	20	40
24-hr Maximum	5	91	182
3-hr Maximum	25	512	700

* The allowable concentrations must in no case exceed the concentrations permitted under the national primary and secondary ambient air quality standards.

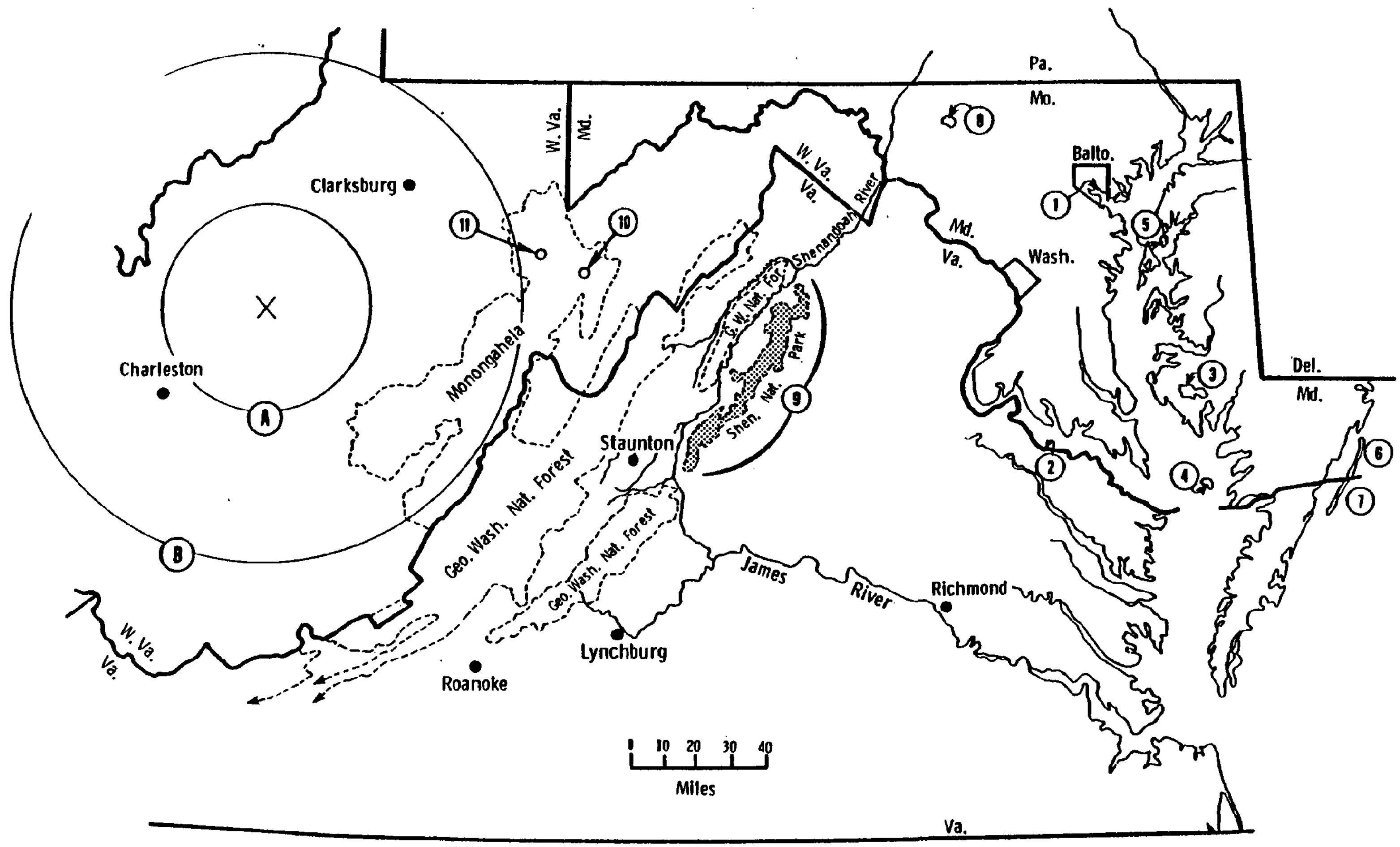

Figure II-16. Mandatory (M) and suggested (S) Class I areas in and around Maryland. There are no mandatory areas in Pennsylvania.

1) Ft. McHenry (S)
2) Washington's Birthplace (S)
3) Blackwater Nat'l Wildlife Refuge (S)
4) Martin Nat'l Wildlife Refuge (S)
5) Eastern Neck Nat'l Wildlife Refuge (S)
6) Assateague Nat'l Seashore (S)
7) Chincoteague Wildlife Refuge (S)
8) Catoctin Mountain Pk (S)
9) Shenandoah Nat'l Pk (M)
10) Dolly Sods (M)
11) Otter Creek (M)

Circle A shows the Class I exclusion area for a 1000 MW power plant located at X burning 1% sulfur coal with an 80% scrubber, and circle B shows the exclusion area for the same plant burning 2% coal (see discussion on p. II-55).

Class II areas have increments allowing moderate industrial growth. All areas of the country not originally classified as Class I start out in this category.

Class III areas are less restricted and may allow fuller industrial development. A Class area may be redesignated Class III only after a process involving the Governor, the legislature, and "general purpose units of local governments." The actual procedure is not determined at this time.

When the allowable increment for an area has been used, an offset policy will probably come into effect. EPA is presently formulating this policy (61). Thus, it may be important to keep this ultimate possibility in mind while evaluating specific plant designs. For example, any coal-fired facility which now burns high-sulfur coal or oil may, during its lifetime, be expected to eventually burn low-sulfur coal or oil (perhaps cleaned to that level). So, it may be advantageous to ensure that the equipment is compatible, or easily convertible, to that type of fuel.

Although the PSD presently applies only to SO_2 and particulates, EPA must establish regulations by August 1979 regarding PSD for hydrocarbons, carbon monoxide, photochemical oxidants, and nitrogen oxides. If national ambient air standards are established for other pollutants at some future date, corresponding PSD regulations must be promulgated within two years of that date.

For power plants which are required to switch to coal as a result of an order under the provision of the Energy Supply and Environmental Coordination Act of 1974, the added concentration due to increased emission will not be applied against the allowable increment for a period of five years. The same consideration applies to plants converting from natural gas as the result of a natural gas curtailment plan implemented under the Federal Power Act.

With the PSD restrictions the question of long-range, interstate transport of pollutants becomes important because a large coal-fired plant, located in Maryland, could use up part of the available increment for up to four states. It is not clear at this time what recourse a state affected by the siting of a source in a neighboring state (and not causing a violation of standard) would have. The present amendments (Section 126) call only for "written notice to all nearby states...at least sixty days prior to the date on which commencement of construction is to be permitted."

To investigate the potential impact of the Clean Air Act Amendments upon power plants within the State, several representative cases have been modeled, using the Gaussian plume model for typical power plants in the following range of variables:

- plant capacity: 100 - 1500 MW
- stack height: 100 - 700 feet
- exit temperature difference: 30°C and 90°C

The lower exit temperature difference is typical for a power plant where the flue gas is not reheated after passing through the SO_2 scrubber, while the higher ΔT corresponds to a moderate reheat. (It is not yet known whether EPA will allow reheat to be considered in calculations). The 1000 MW power plant used in the modeling has a stack diameter of 35 feet, an exit velocity of 41 feet per second, burns two percent sulfur coal, and utilizes a ninety-nine percent efficient particulate precipitator and an eighty percent efficient SO_2 scrubber for emission control. With these parameters, the numbers quoted for sulfur dioxide concentrations can be converted to particulate levels by dividing the quoted concentration by 5. The SO_2 ground-level concentrations scale directly as power level, sulfur content of the coal, and percent of SO_2 emitted from the scrubber. The calculations are for flat terrain, and thus would not apply in the rough terrain of western Maryland (in rough terrain, the specific locations of mountains, valleys, and stacks must be considered in each individual case).

The annual average ground-level concentration depends primarily on meteorological conditions, as defined by the annual windrose (considering stability class and wind persistency); by the difference ΔT, between the flue gas exit temperature and the ambient temperature; by the physical stack height; and by the power plant emission rate (which depends on power level, in addition to the sulfur content and scrubber efficiency as discussed above). Using the windrose at the Baltimore-Washington International Airport (BWIA) as a representative case for Maryland, the annual average ground-level concentrations were calculated for several plant configurations. These results are summarized in Figures II-17 and II-18, which show the maximum annual average of SO_2 as a function of power generated and stack height. In all cases for moderate stack heights (500 feet), the increase in concentration is less than twenty-five percent of the Class II increment.

Two meteorological situations have been considered in order to establish the worst situation to compare to the 24-hour average increment.

1) Neutral atmospheric stability with high wind (8m/sec) and persistent wind direction.

2) Unstable atmospheric conditions with light wind, typically for 8 hours followed by persistent wind direction and stable conditions for 16 hours.

These conditions occur rarely in Maryland (only a few times a year), but, depending upon location, may occur frequently enough to be the determining factor in a plant siting decision. Results of calculations for these meteorological conditions, shown in Figures II-19 and II-20 for a plant employing reheat, indicate that a 1000 MW plant with a 500 foot stack would be allowed in a Class II area, although a significant percentage of the allowable increase (up to fifty percent) in Class II regions would be used. Thus, depending upon the local frequency of these meteorological conditions, the siting of a power plant might lead to future sources requiring an offset. For conditions other than the two named above, 24-hour average concentrations would typically lie below 30 $\mu g/m^3$ for a 1000 MW plant with a 500 foot stack.

Calculations for the three-hour average indicate it is not a restraining factor for PSD in a Class II area.

The final area of concern, long range transport of SO_2 into Class I areas, is a difficult area to analyze. The Gaussian plume model is not accurate at

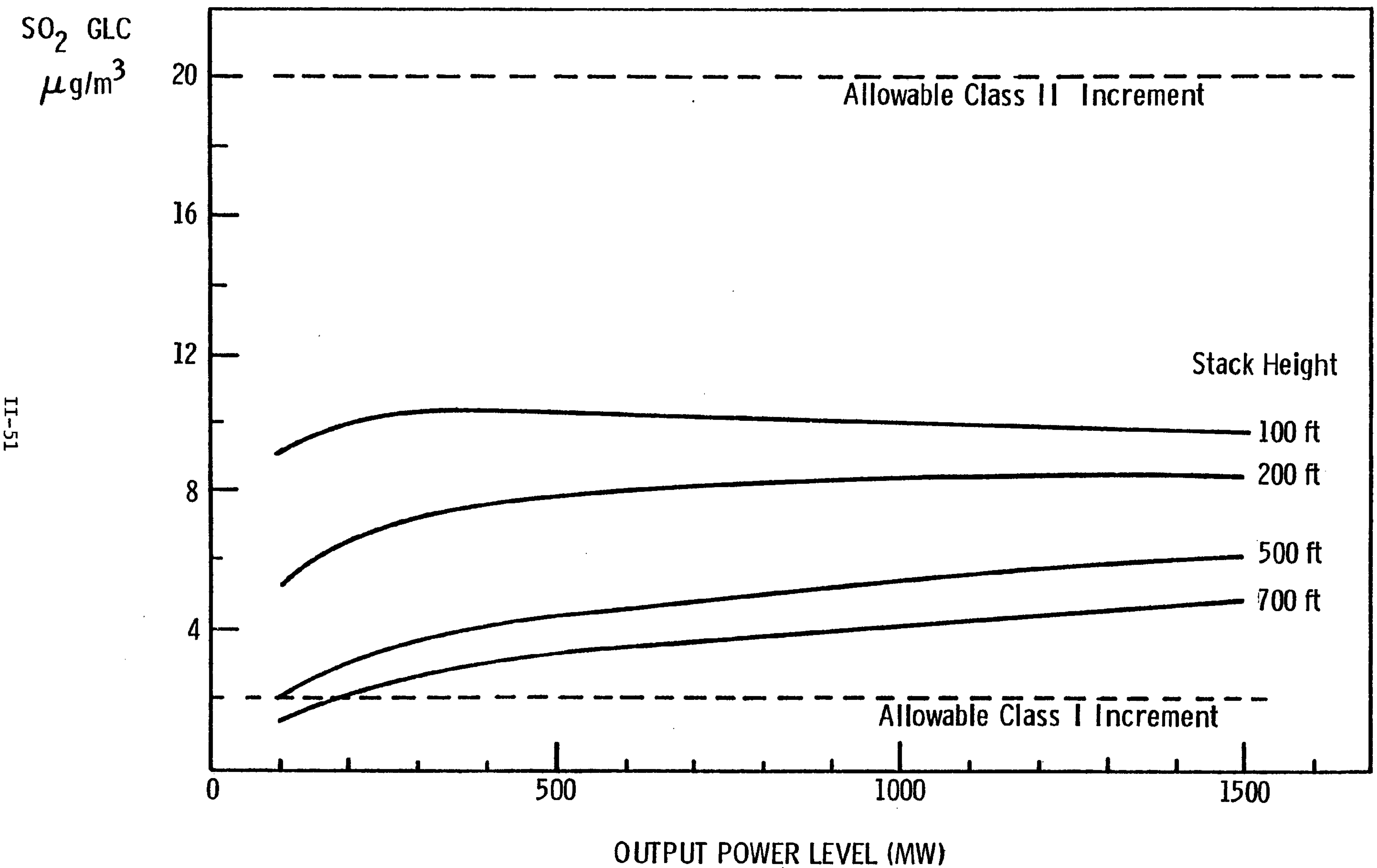

Figure II-17. Maximum annual average ground-level concentration for SO_2 $\Delta T = 30^{o}$ C

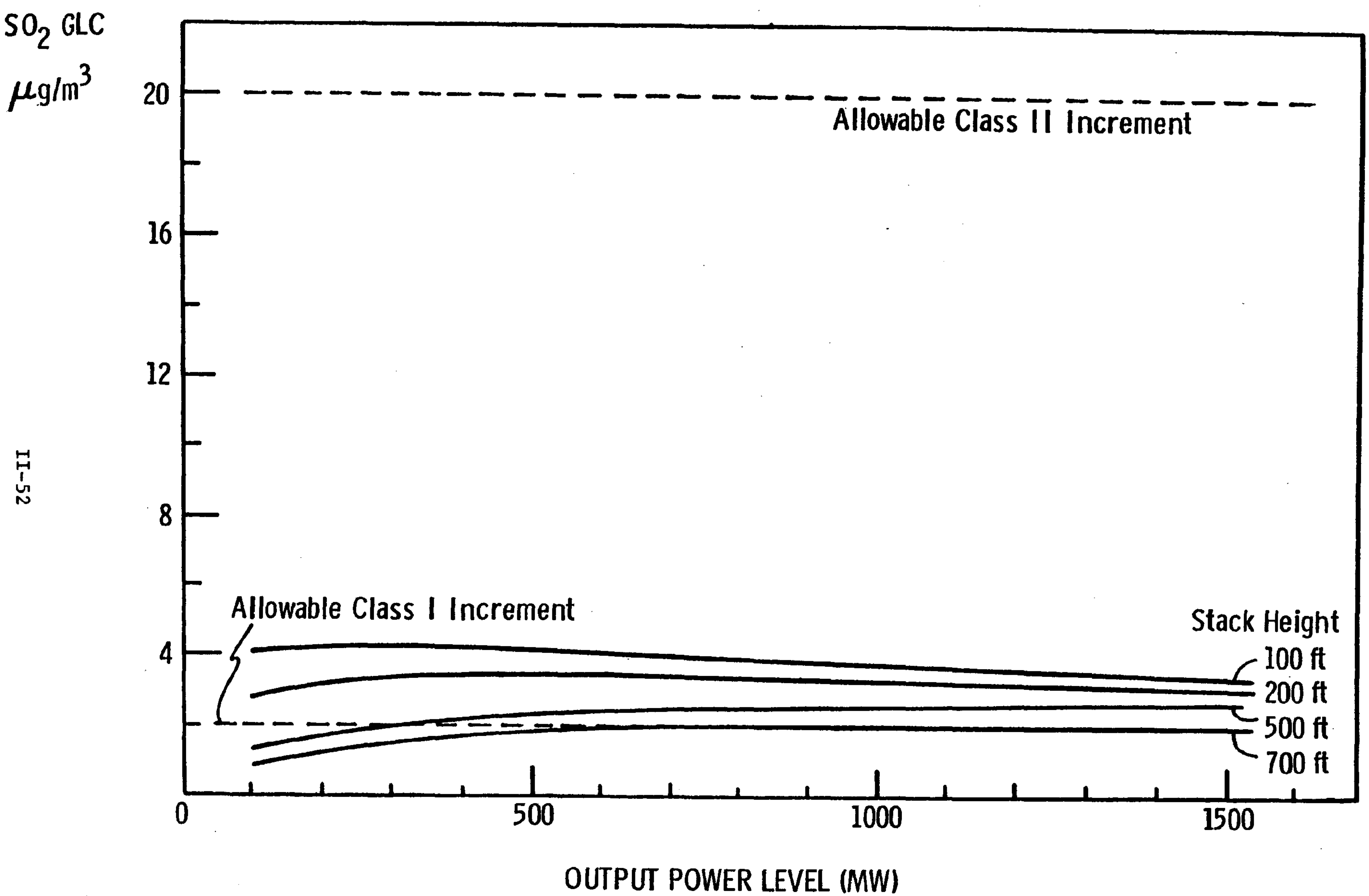

Figure II-18. Maximum annual average ground-level concentration for SO_2 $\Delta T = 90^{\circ}$ C

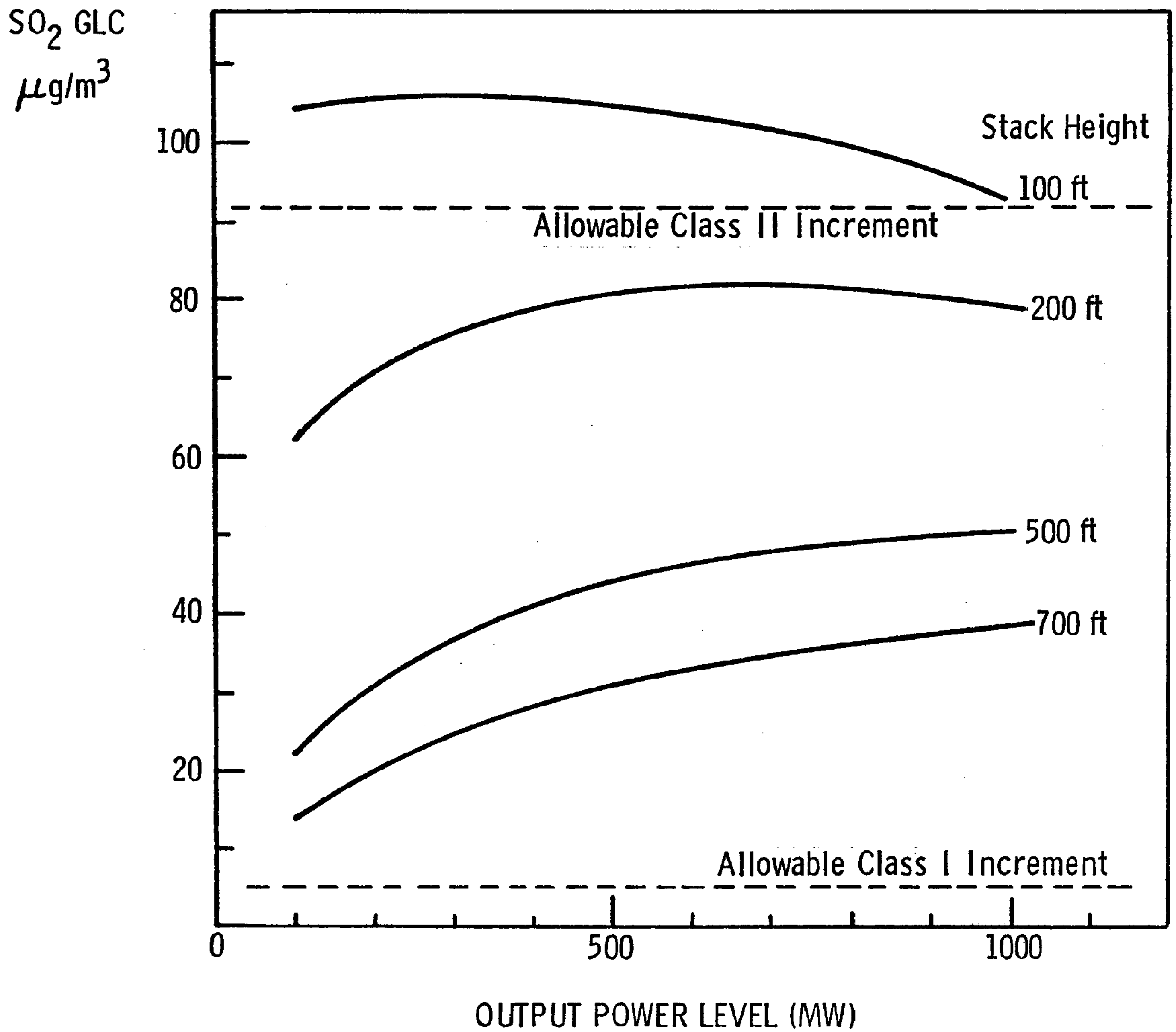

Figure II-19. Maximum 24-hour average ground-level concentration for SO_2
Meteorological Condition 1 $\Delta T = 90°C$

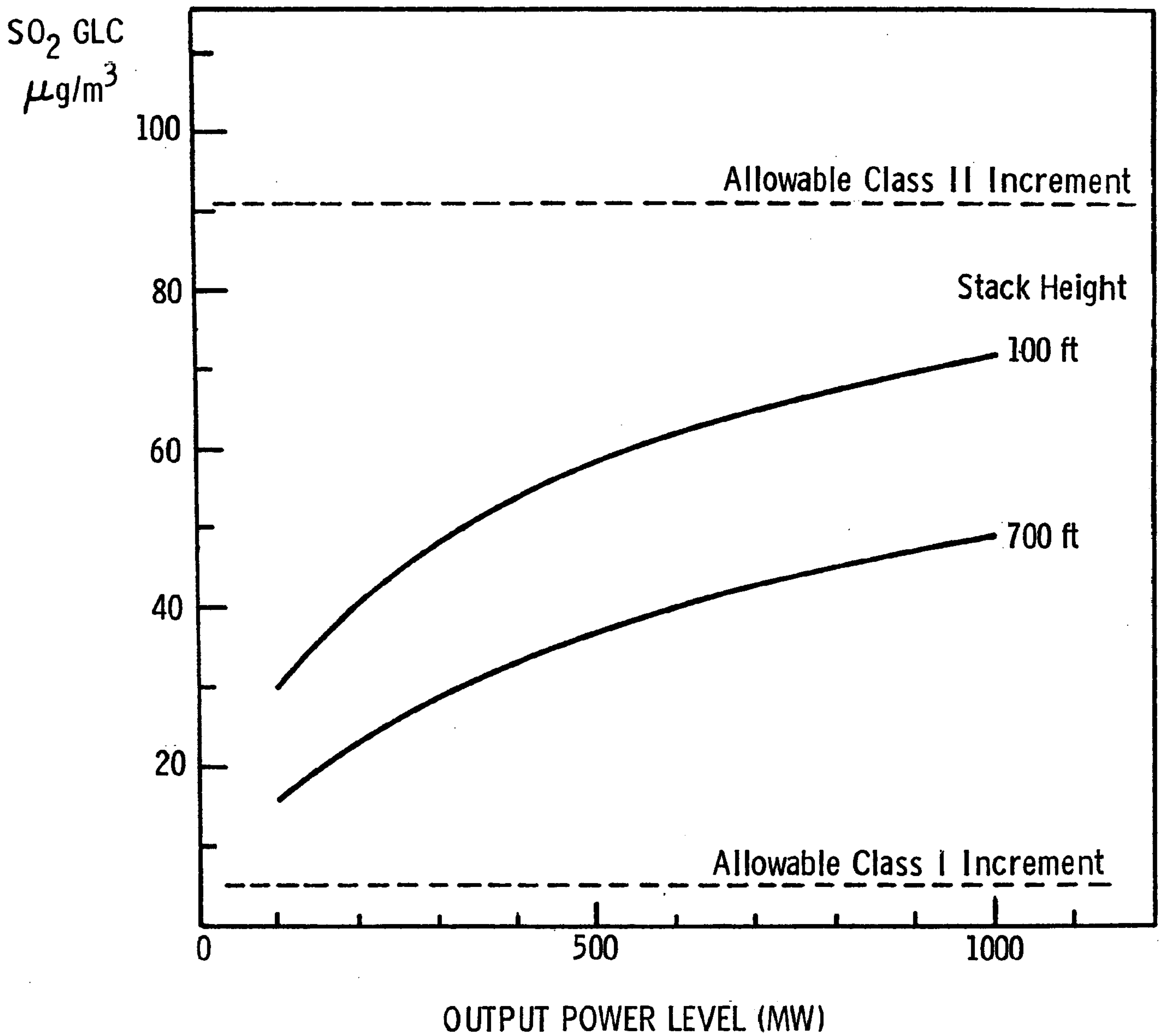

Figure II-20. Maximum 24-hour average ground-level concentration for SO_2 -- Meteorological Condition 2 $\Delta T = 90°C$

distances beyond 20-30 miles (as explained in Section F), the meteorological data necessary for realistic calculations (high level and profiles every 20-30 miles) are not available, and the interaction of pollutant plumes from various sources is not well understood. One indication of this difficulty is the large difference in the annual windrose from National Airport, Dulles Airport, BWI, and Patuxent Naval Air Station (as shown in Figure II-21). Despite the fact that all four airports are located within a 50 mile radius, the windroses are different. A plume emitted at National might change direction by the time it reached Southern Maryland or Baltimore, and vice-versa. Still, by looking at various limiting cases, we can gain insight into the effect of a Class I area upon power plant siting. The two meteorological conditions mentioned above give upper limits to the "zone of influence" (the maximum distance) from which a power plant would be excluded. A more common condition, medium winds (5 m/sec) for 10 hours followed by stable conditions, gives the minimum exclusion distance. The exact exclusion area (to be determined by site specific meteorological studies) would be somewhere between the two. The results of these calculations are shown in Figures II-22 and II-23. Although the Gaussian plume model is not adequate to deal with transport over these large distances, we obtain the following indications (see Figure II-24).

A 1000 MW power plant using a 500 foot stack and burning two percent sulfur coal with an eighty percent scrubber could not be located closer than 90 (and possibly not closer than 200) miles to a Class I area. If the same plant burned one percent sulfur coal, the plant could not be located closer than 40 (and possibly not closer than 75) miles to a Class I area. Thus, the designation of a Class I region in, or nearby, Maryland could:

- limit a substantial portion of the State to allow only the siting of small fossil-fueled plants,
- make the operation of new plants more expensive by requiring the use of low-sulfur in addition to scrubbing, and
- encourage the use of nuclear power because of the two points made above.

In summary, the effects of the PSD provisions of the Clean Air Act will be to:

- limit the increase in pollutant levels,
- require power plants to locate moderate distances away from each other and from other major emission sources, and
- establish power plant exclusion zones around Class I air quality regions.

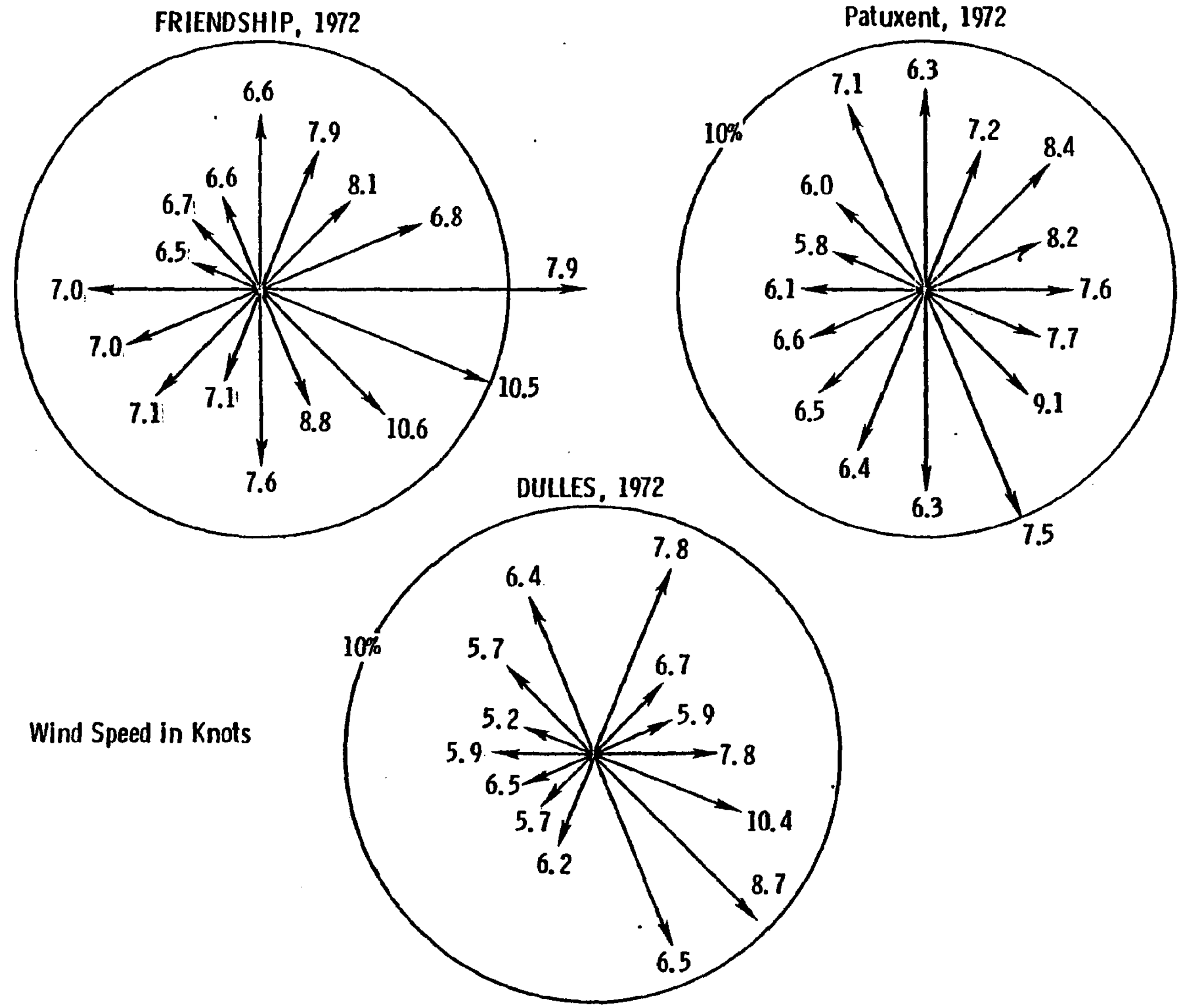

Figure II-21. Annual wind roses for three airports. Length of arrow shows frequency of occurrence (in percent of time - Note 10 percent circle) of wind blowing towards the indicated direction. Number at tip of arrow shows annual mean wind speed (in knots) in that direction.

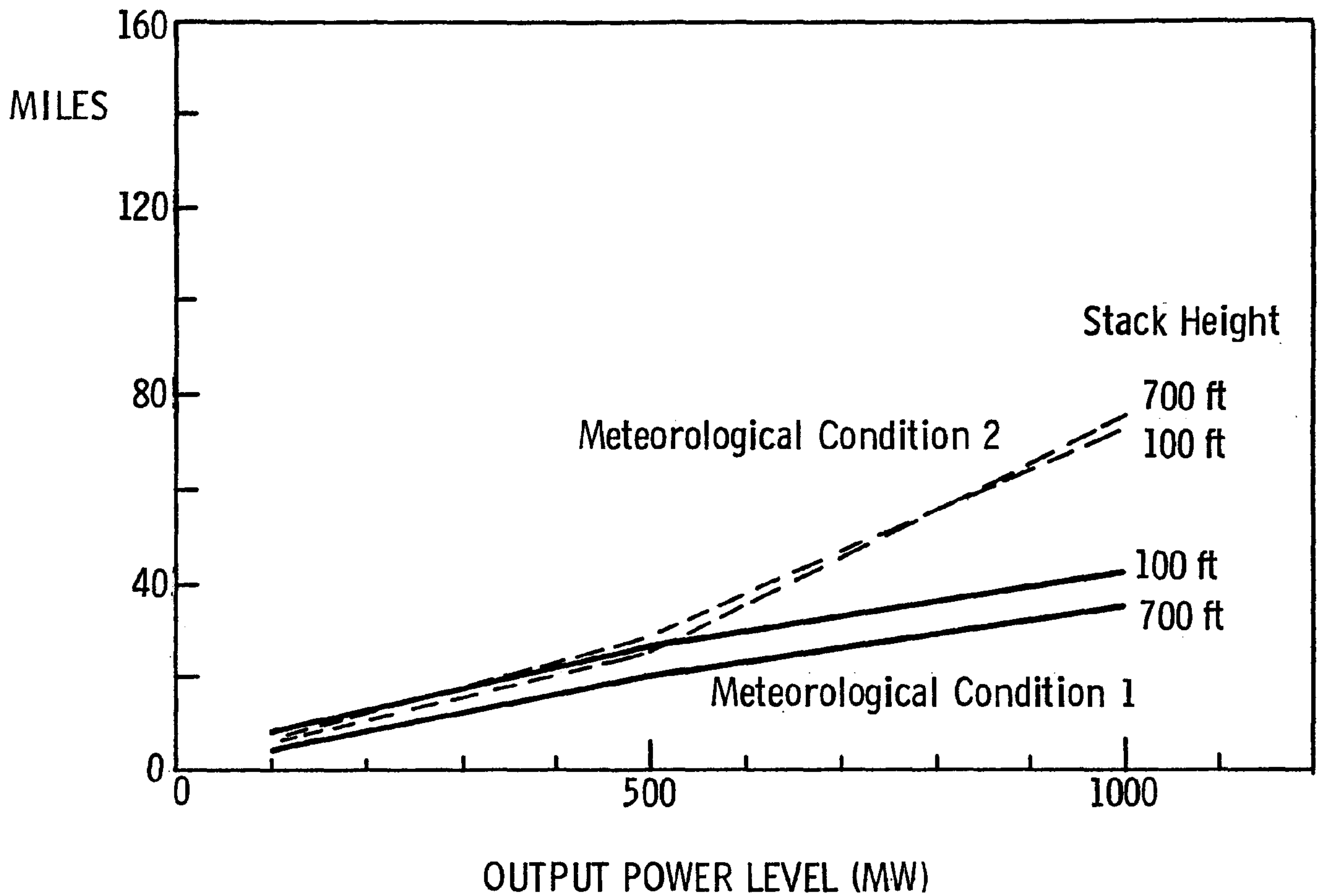

Figure II-22. Distance to ground-level concentrations of 5 μg/m^3 SO_2 (Class I area increment) 1% sulfur coal, 80% efficiency scrubber $\Delta T = 90°$ C

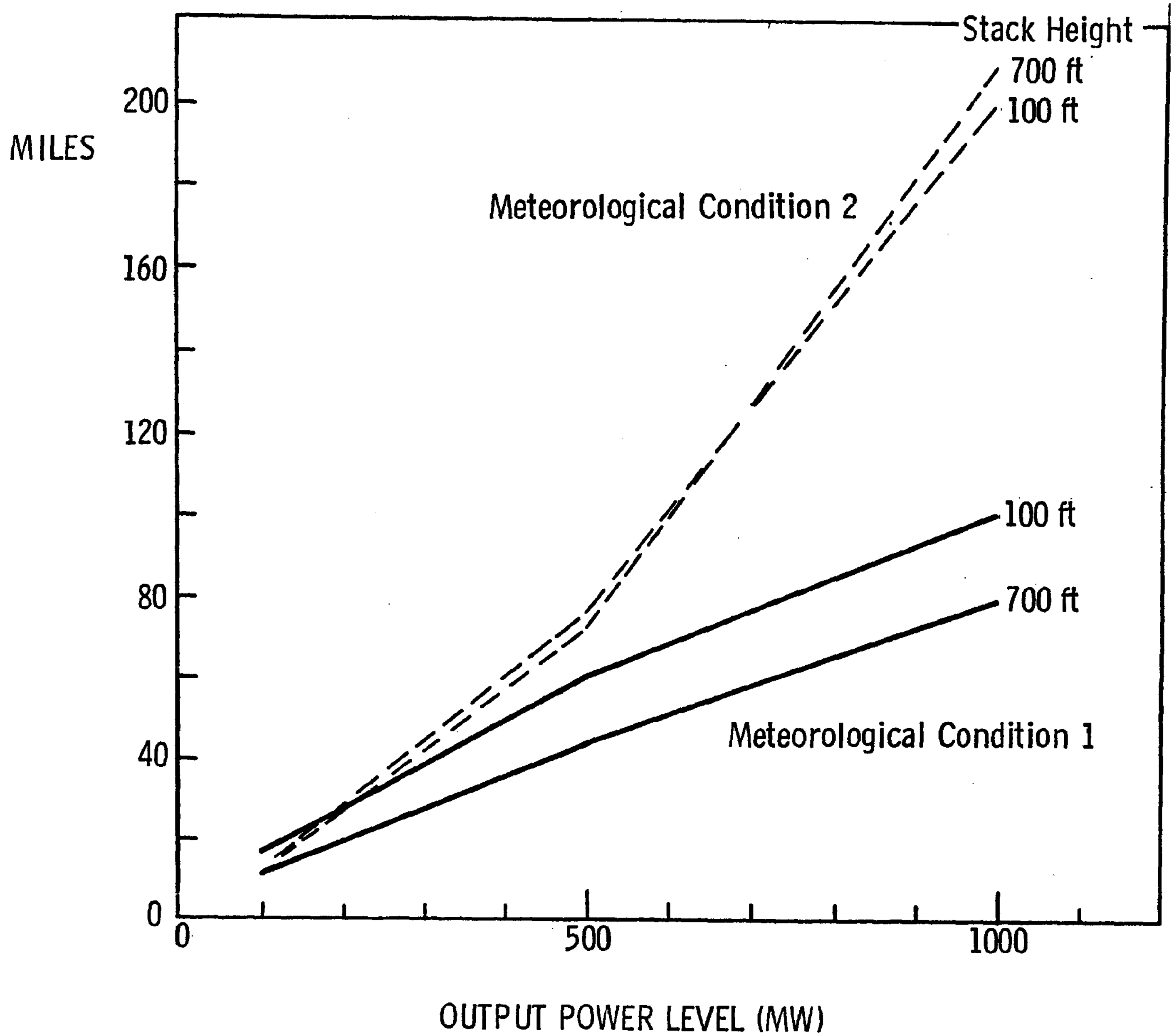

Figure II-23. Distance to ground-level concentration of 5 μg/m^3 SO_2 (Class I area increment) 2% sulfur coal, 80% efficiency scrubber ΔT = 90°C

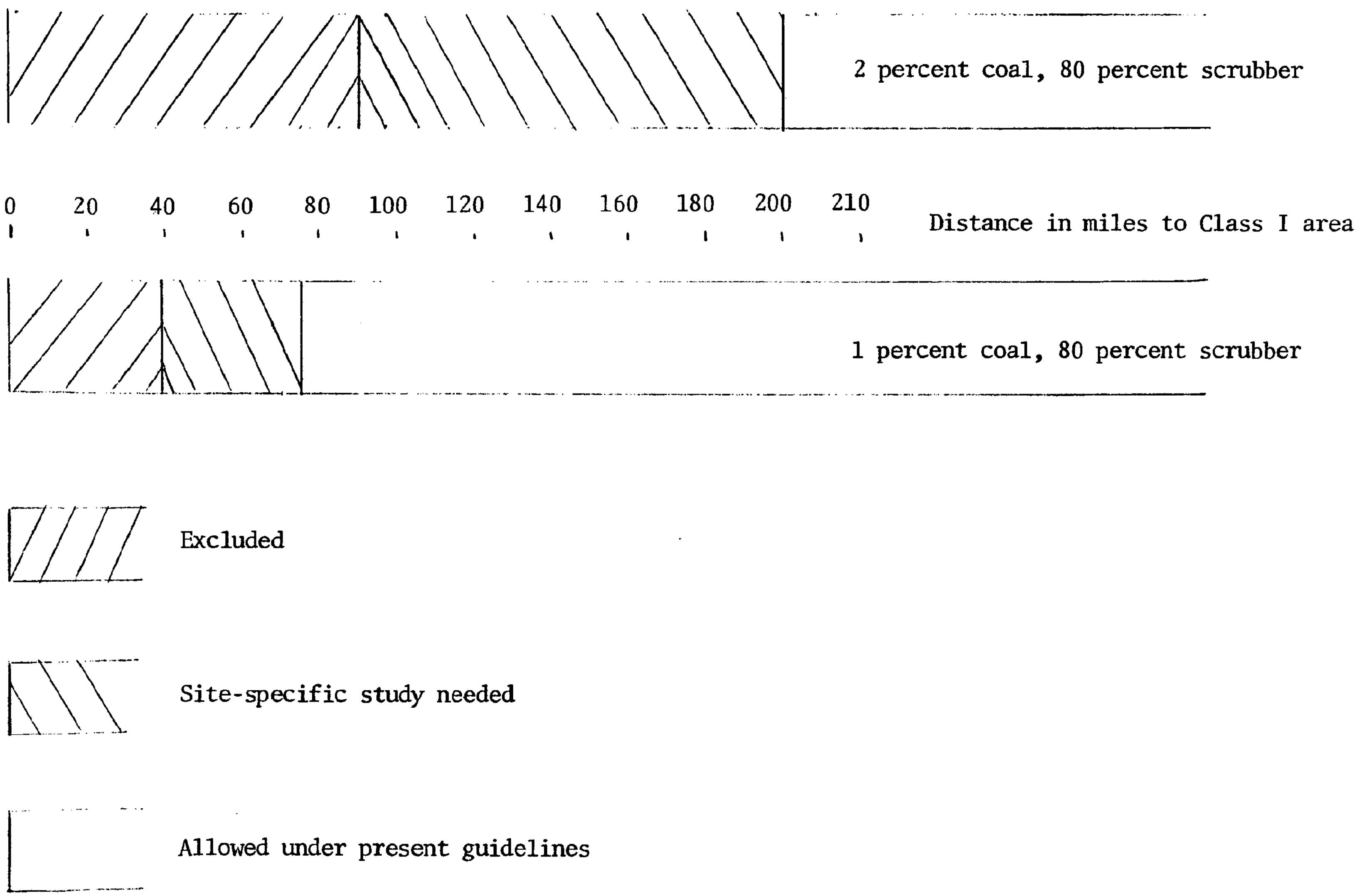

Figure II-24. Siting Restriction for a 1000 MW coal-fired plant with a 500 ft stack relative to a Class I area.

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CHAPTER III

AQUATIC IMPACT

For each kilowatt hour of electricity generated, a steam power plant burning fossil fuel must dispose of about 4,400 BTU of heat via its condenser, and a nuclear power plant must dispose of about 6,600 BTU. Most Maryland power plants use once-through cooling systems to transport this waste heat from the plant. In these systems, water is drawn into the plant, heated 10 to 17°F in the condenser, and discharged into a receiving body of water. Approximately 1 million gallons of water per minute (or 63 m^3/sec) is required for each 1000 MW of generating capacity. Even when closed cycle cooling can be used to reduce water withdrawal (as discussed in Chapter VI), there may still be a significant amount of water withdrawn.

The Chesapeake Bay and its tributaries serve as the major source of cooling water in Maryand. At the same time, they also support complex aquatic food chains that produce renewable resources of fish and shellfish. A major concern of the Power Plant Siting Program is that power plants, while providing electricity at a reasonable cost, do not interfere with the maintenance of sustained yields of resource species, which are dependent on all food chain components. Thus, the impact of power plants on the aquatic ecosystem as a whole must be evaluated and measures to mitigate this impact should be examined for their potential benefits and costs.

As water is drawn through the power plant and returned to its source, aquatic organisms interact with cooling system structures, with intake and discharge velocity fields, with the heated effluent, and with other alterations of the environment caused by plant operations as explained below.* The locations and nature of these interactions are shown schematically in Figure III-1. The following types of interactions and stresses are encountered by aquatic organisms:

- Entrapment

  Two of the largest Maryland power plants (Calvert Cliffs and Morgantown) have intake embayments partially shut off from the main bay or river by a curtain wall, i.e., a wall reaching from above the surface of the water to some depth below the surface. The function of the curtain wall is to permit the plant to draw its cooling water from the deeper portions of the water column, where temperatures tend to be lower than at the surface during summer months. Large numbers of fish congregate in intake embayments during the summer where they may be entrapped. During the summer months, dissolved oxygen (DO) concentrations in the water often drop to levels below that needed to sustain adult and juvenile fish. The drop is pronounced in the deeper water entering the embayment under the curtain wall. Fish kills may result, and the killed (or weakened) fish may then impinge in large numbers on the protective intake screens.

* Radiological effects are discussed in Chapter IV.

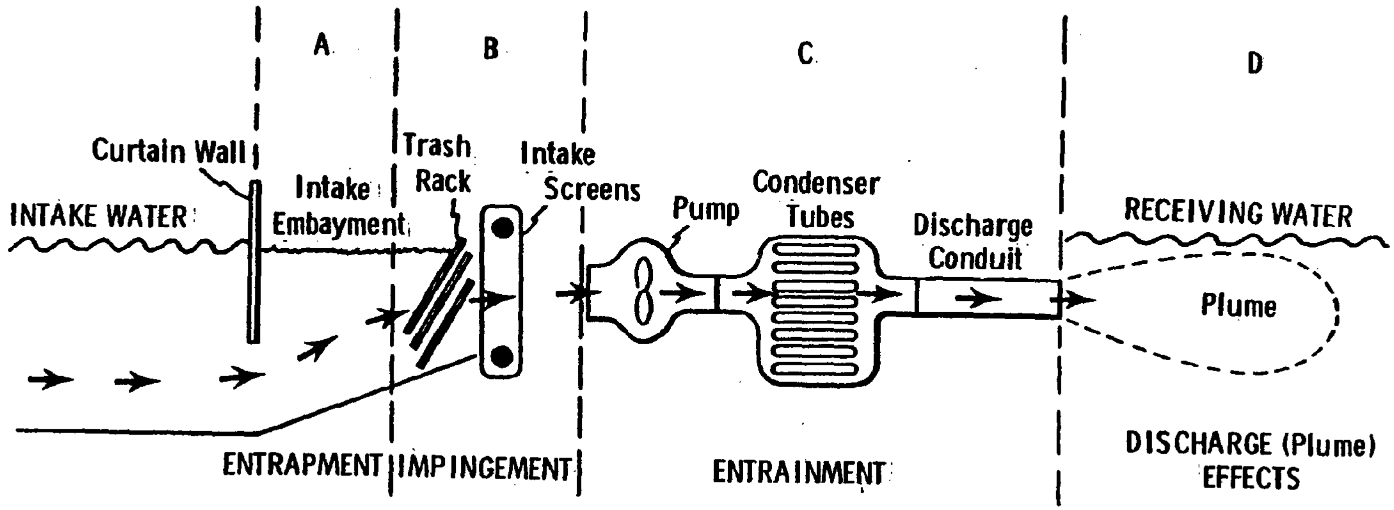

Figure III-1. Path of cooling water flow through a power plant and locations of plant-organism interactions.

A. Fish may be entrapped in the intake embayment and may suffer prolonged exposure to water of low dissolved oxygen content drawn from below the curtain wall.

B. Organisms may be trapped on intake screens; the screens are rotated to wash fish and crabs from the screens back into the receiving water.

C. Small organisms in the water column (plankton) pass through the cooling system; they experience a temperature rise and also shear and pressure forces during their cooling system transit.

D. Organisms in the receiving water may encounter plume temperature rises (and may be affected by the velocity of the discharge).

- Impingement

  The circulating pumps for the cooling water are protected by intake screens (usually 3/8 inch mesh). Organisms too large to pass through these screens may be impinged, i.e., pinned against it by the pressure of the passing water, a prospect that is markedly increased when the organisms (fish or crabs) are weakened by stresses such as low DO condition. The screens are rotated periodically and the impinged matter is washed off and usually flushed back into the cooling stream discharge. Some species survive this treatment, but others suffer a high rate of mortality.

- Entrainment

  Organisms small enough to go through the intake screens pass through the entire cooling system, where they are stressed by mechanical forces due to physical contact with pumps and pipes, and pressure and shear forces generated by complex flow patterns and turbulence.

  While passing through the condenser, the entrained biota will be subjected to a sudden temperature rise. The biological response to this heating depends on the magnitude of the temperature rise, the length of exposure to the elevated temperature, and the initial ambient temperature. Temperature rise varies from 10°F to 17°F in Maryland plants, and exposure time from a few minutes to almost two hours (including retention time in effluent canals). Thus, thermal stress "dose," i.e., product of temperature and time is quite variable.

  Additional stress is experienced by entrained biota at plants where biocide (usually chlorine) is added to the cooling water to prevent clogging of the cooling system by built-up biomass.

- Discharge Effects

  The alteration of local habitat produced by the discharge of cooling water can manifest itself in several ways. Aquatic organisms can be "entrained" into the discharge plume, where they will be exposed to higher-than-ambient temperature and biocide residuals. Other toxic substances released with the cooling water (e.g., copper) may affect the stationary benthic communities near the plume. Finally, fast-moving discharge flows cause alterations in the characteristics of bottom sediment in the discharge zone, and also directly influence the behavior of some organisms.

The trophic levels and life stages of organisms interacting with the power plant can be grouped as follows:

- phytoplankton
- zooplankton
- benthos

- ichthyoplankton

- juvenile and adult fish and crabs

Individual groups may be more susceptible to damage by one type of power plant interaction than by another (Table III-1). Entrapment can stress juvenile fish. Entrainment stresses planktonic organisms, which serve as food for many resource species, as well as the planktonic larval stages of many resource and forage species. All aquatic biota may experience discharge effects but benthic species, because of their predominantly immobile life style, would be most stressed.

Mortalities resulting from plant-organism interactions can cause a decline in a population if they are not offset by biological compensation mechanisms such as increases in growth rate, fecundity and/or early survival. In the case of phytoplankton or zooplankton, losses due to entrainment are generally recouped quickly as a result of rapid reproduction (generation times of hours to days). Other organisms have much longer generation times. Fish spawn only once a year, and may not reproduce until several years of age. For species utilizing a very localized spawning or nursery area adjacent to a power plant, high entrainment losses can occur unless cooling towers with carefully controlled blowdown are used to reduce the exposure. The potential for such losses is much less for ubiquitous species which spawn in or inhabit wide areas of the Bay.

Plant operations can indirectly cause decline of a population by decreasing the abundance of its food supply. The dominant groups in the Bay which are important as forage are phytoplankton, zooplankton, benthic organisms, and small fish species (e.g., Bay anchovy and menhaden). Although fish populations are more likely to be affected by the entrainment of their ichthyoplankton, they could also be affected by a change in the density of their food (see Figure III-2). These indirect effects may propagate through several trophic levels, although they are unlikely to be measurable beyond one link along the food chain.

Plant operations also affect particular species through modification of the physical/chemical environment. Biocide residuals may accumulate in areas around the plant, and temperatures are elevated by varying amounts in the discharge vicinity. Discharge jets may also scour the bottom sediments, creating locally uninhabitable zones for benthic organisms. If such habitat modificatons make an area unsuitable for use by some species, a subsequent decline in their abundance can occur locally.

A. Aquatic Habitat

The central concept underlying the cumulative aquatic assessment presented here is that Chesapeake Bay and tributary estuarine waters are composed of distinct habitat types. These habitat types are defined by water salinity, which is the environmental variable most important in controlling distributions of organisms in estuaries. Each of these habitats can be identified with unique functions in producing or supporting important resource elements, although their biotic compositions gradually change into one another, and their extent varies seasonally. Cumulative impact will be assessed in terms of

Table III-1. Major types of aquatic effects of power plant operations

Sources of Effects	Primary Susceptible Organisms	Type of Stress				
		Low DO[a]	Mechanical	Thermal	Chemical	Habitat Alteration
Entrapment	Fish	x	-	-	-	-
Impingement	Juvenile fish, crabs	-	x	-	-	-
Entrainment	Ichthyoplankton[b] Zooplankton[c] Phytoplankton[d]	-	x	x	x	-
Discharge Effects	Adult and juvenile fish, benthos[e] shellfish	-	-	x	x	x

(a) Low dissolved oxygen concentrations -- oxygen deficiency
(b) Eggs and larvae of fish
(c) Minute animals present in the water
(d) Minute plants present in the water
(e) Organisms living in or on the bottom

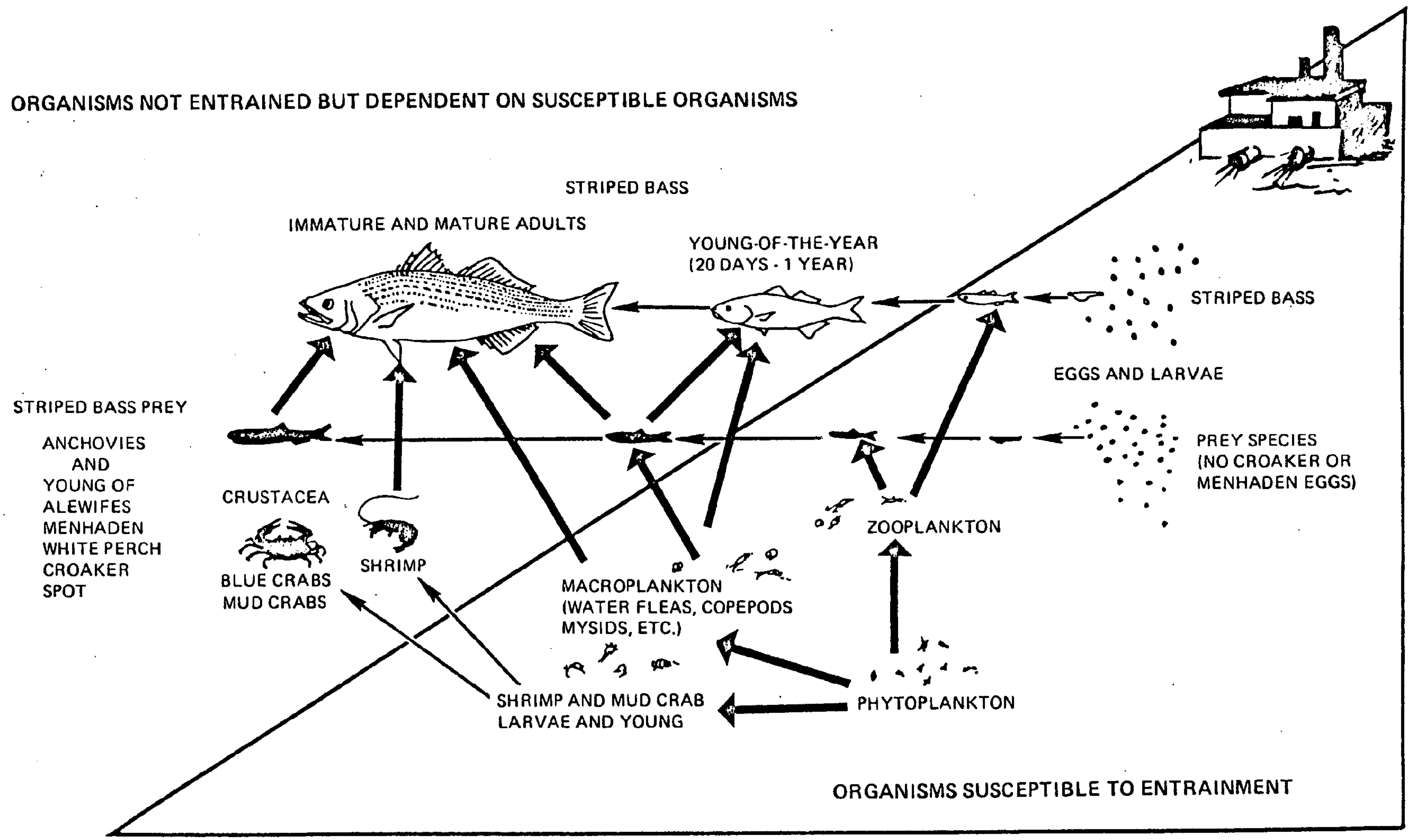

Figure III-2. Areas of potential power plant entrainment impact on striped bass and associated food items.

significant effects on the biota over the entire extent of each characteristic habitat type within Maryland, with the emphasis on whether the long-term integrity of each estuarine habitat and its characteristic functions are maintained.

The salinity zones designating the habitat types can be defined by the Venice system of classification (1) as:

Habitat	Salinity Ranges
Euhaline (Marine)	30.0 ppt - 35.0 ppt
Polyhaline	18.0 ppt - 30.0 ppt
Mesohaline	5.0 ppt - 18.0 ppt
Oligohaline	0.5 ppt - 5.0 ppt
Tidal fresh	0 ppt - 0.5 ppt
Riverine	0 parts per thousand (ppt)

The following major ecological functions of each habitat may be listed:

- Polyhaline and Marine

  These high salinity waters are primary sites of blue crab spawning and development, and also support hard clams. Several fish species, (e.g., spot, croaker, and menhaden) whose young and adults seasonally feed in upper estuarine zones, spawn and develop in these regions. These zones generally do not exist in the Maryland portion of the Chesapeake Bay.

- Mesohaline

  These medium salinity regions are the primary areas of shellfish production (clams, oysters) whose early life stages are planktonic. Mesohaline waters also support the adult crab populations. They produce most of the estuarine forage fish biomass, and therefore, serve as feeding areas for large predator fish (e.g., bluefish, striped bass).

- Oligohaline

  These brackish water environments support resident estuarine fish populations, and serve as spawning and nursery grounds for them. These fish populations serve primarily as forage organisms for larger fish, but may also be exploited by man (e.g., white perch). The areas are also feeding grounds for migratory marine and estuarine species such as menhaden and white perch. Some spawning of anadromous fish also occurs here.

- Tidal Fresh

  Segments of estuaries within tidal influence but without a significant salt intrusion provide spawning and nursery areas for anadromous fish species, also supporting their larvae and juveniles during spring and summer months. In addition, resident fish species, some adapted to both this and riverine environments, spend their entire life cycles in this zone. The striped bass is a particularly important example of a species using this environment as a spawning and nursery area.

- Riverine

  These freshwater habitats beyond the head of the estuary have resident fish populations and supporting bottom (benthic) communities adapted to constant freshwater conditions.

The location of these zones change seasonally as a result of changes in the amount of freshwater inflow (see Figure III-3). Table III-2 indicates the zones in which power plants in Maryland are located, and shows locations according to season. The majority of plants in Maryland are situated in tidal fresholigohaline regions. However, the largest in the State (Calvert Cliffs, Chalk Point, and Morgantown) are sited in mesohaline regions (at least in the fall) and new plants (e.g. Elms) will also be in the mesohaline habitat. There are no power plants in the polyhaline and marine habitats along the Atlantic shoreline in Maryland.

B. Assessment and Mitigation of Impact

Environmental impact assessments are carried out by the Maryland Power Plant Siting Program. These assessments consist of predictions of the effects of the power plant construction and operation, evaluations of the impact of these effects upon the aquatic resources of the State and determination of measures to minimize adverse impacts.* At several existing plants there are monitoring programs for detecting and quantifying these effects and for measuring and analyzing their impact.

For new plants, after regional surveys have quantified the existing populations, the local impact of each effect is predicted and related to regional impact on populations of affected organisms. The aquatic impacts are, as much as possible, described in terms of percent reduction of local and regional populations, the possible indirect effects on other organisms, and the impact on man's use of the resources. Where appropriate, a sensitivity analysis is performed to reveal the consequences of uncertainties in knowledge or assumptions. Feasible alterations in plant design which might reduce impacts are evaluated with respect to benefits and costs. Those alterations which are found to have sufficient benefits are recommended to the appropriate regulatory agency (e.g., the Public Service Commission or the Nuclear Regulatory Commission) for incorporation into the decision process for a construction permit. For example, in the course of the detailed site evaluation of Douglas Point, a plant design alternative was identified which would reduce the water withdrawn from the Potomac River by a factor of three. Entrainment of fish eggs and larvae would thus be reduced by the same factor. This proposed design alternative was accepted by the utility. Sometimes detailed predictions of the most probable impact are not possible, and a conservative analysis must be used (e.g., assuming 100% mortality of impinged fish where no specific mortality studies have been done).

The monitoring phase consists of detection and quantification of power plant effects, and evaluation of the significance of these effects in altering resource

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* An effect is a measurable change. An impact is an effect that is judged to be significant.

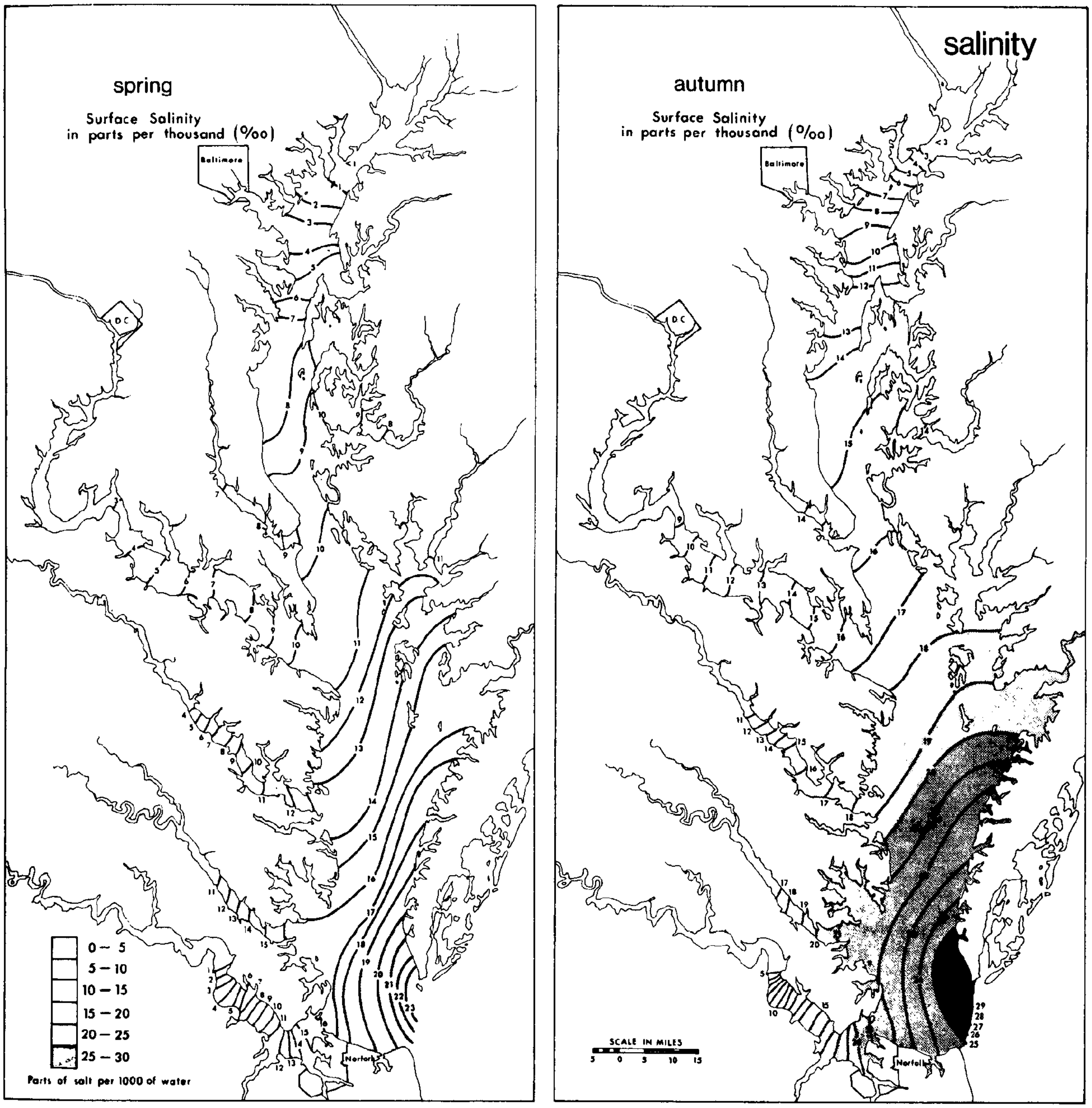

Figure III-3. Spring and autumn salinity distributions in the Chesapeake Bay. From: The Chesapeake Bay in Maryland. Editor Alice Jane Lippson. The Johns Hopkins University Press. Baltimore. Copyright 1973 by the Johns Hopkins University Press (by permission).

Table III-2. Power plant location by salinity regime

Power Plant	SPRING				FALL			
	Riverine	Tidal-fresh	Oligo-haline	Meso-haline	Riverine	Tidal-fresh	Oligo-haline	Meso-haline
Benning Rd.		x				x		
Brandon Shores		x					x	
Buzzard Pt.		x				x		
Calvert Cliffs				x				x
Chalk Pt.			x					x
C.P. Crane		x					x	
Dickerson	x				x			
Douglas Pt.			x				x	
Gould St.		x					x	
Riverside		x					x	
Wagner		x					x	
Westport		x					x	
Morgantown			x					x
Possum Pt.		x					x	
Potomac River		x				x		
R.P. Smith	x				x			
Summit *								
Vienna			x				x	
Conowingo (Hydro)	x				x			

* The proposed Summit plant is on the C&D canal. Salinity varies irregularly from tidal fresh to mesohaline. The monthly average at the plant site is generally below 5 ppt (37).

yield and ecosystem stability. To learn how losses of organisms due to entrainment, impingement, and plume effects indirectly alter population sizes in the receiving body, populations must be monitored over a considerable span of distance and time. Plant-induced changes (if any) must be separated from natural and other man-induced changes that occur seasonally, annually, or irregularly. To determine the direct damage caused by entrainment, the number and condition of organisms are measured as they enter and leave the plant with the cooling water. Impingement damage for each species is determined from samples taken from screens. These measurements show which species are directly affected in-plant, and to what extent they are affected. Plume effects are determined by measuring changes in abundance or distribution of organisms in the area exposed to temperature increases and other discharge related environmental alterations.

The results of ongoing studies at existing plants are applied to mitigate impact. Where these studies identify plant-related effects, alternative operating schemes and changes in plant design are evaluated as to their benefits and costs. Examples of this are changes in the intake structure at Calvert Cliffs (discussed under the mesohaline section of this chapter) and the ongoing evaluation of augmentation pumping at Chalk Point and Morgantown (2,3). Monitoring results will be applied to the design of future plants. For example, it is extremely unlikely that any new plant would be built with a long discharge canal or low velocity discharge because of the deleterious effects that have been associated with such systems (2,3,4).

The procedures used to assess the ecological significance of plant-induced population changes will vary according to the group of biota considered. For plankton, the concern may be about the result of a localized depletion in terms of yields of higher trophic levels. In the case of fish, the magnitude of plant-related kills might be compared to commercial or recreational harvests. Once the effect has been quantified, the determination of the acceptibility or unacceptibility requires a value judgement, and thus there is a degree of subjectivity associated with the specific determination.

C. Aquatic Impact

Because aquatic impact is a consequence of withdrawal and discharge of cooling water, the magnitude of cooling water flows in relation to the size and flow rates of the water bodies on which plants are sited provides an index of potential impact. These flows contribute to the mixing and transport of the cooling water effluent, and they determine the size of the zone of physical and potential biological alterations. The dilutions of heated water and toxic materials, and the mixing of biota-depleted volumes of cooling water into ambient waters, influence the ability of the habitat to accept the power plant effects without significant ecosystem alterations.

In riverine waters, flow is unidirectional and varies with the amount of rain water run-off. The ability of such a flow regime to meet cooling flow requirements of a power plant, while maintaining environmental integrity, is indicated to some extent by the relative amounts of river flow (usually mean annual low flow) and plant cooling flow.

Estuarine flows are complex and vary from the upper to the lower reaches. Tidal oscillations of the water are superimposed on the unidirectional river flow, and usually exceed it in magnitude. Thus, although water masses may oscillate several times past a given location, net river flow continually brings new water from upstream and flushes "resident" water downstream. Because of tidal influence, discharges from estuarine power plants have residence times near a particular location which are greater than at riverine plants. However, because of the large volume tidal flows, effluents are more readily dispersed and diluted than in rivers.

As salinity increases down-estuary, the non-tidal circulation patterns in the estuary become more complex (see Figure III-4). As the fresh river water flows downstream, it entrains denser (i.e., heavier) salt water from below. A gravitational convection pattern (enhanced by tidal mixing) develops in the lower estuary (extending to some degree to the tidal fresh region). Downstream mass transport in the upper layer will now exceed the river input. To maintain continuity of mass, saline bottom water from downstream must replace the water convected vertically upwards creating an upstream net flow in the lower layers. Thus, opposing non-tidal flows develop, flowing downstream on the top and upstream on the bottom. These flows are superimposed on the tidal flow and may exceed the river input both in the upstream and downstream direction. The difference between these opposing flows is, however always equal to the river input at any point along the estuary. In a general way, we can view these large non-tidal flows as providing high rates of flushing of power plants effluents, while the tidal flows generate dispersion and dilution.*

In this context, there are several characteristics of each power plant and its adjacent water body which are important in assessing the potential impact of the plant. As a result of tidal flows which reverse direction over a single cycle, water originally outside the plant will make an upstream or downstream excursion from that point over the period of that cycle. These double tidal excursion distances define a localized reference volume and area, (see Figure III-4), to which the amount of water used by the plant and the dimensions of the discharge plume may be compared. Ratios of non-tidal river flow to plant flow given an index of the rate of advection (flushing of discharge) away from the site. Ratios of root-mean-square tidal flow to plant flow can be considered as indicators of dispersive potential at a site. The tidal surface area can be compared to the area of the thermal plume (which represents an area over which a direct physical effect is measurable).

The volume of water present within a double tidal excursion distance of the plant can be compared to the volume of water which has passed through the plant over various significant periods of time. Such comparisons have greatest relevance when considering potential plant effects on phytoplankton and zooplankton. These organisms exhibit rapid reproduction (5) (phytoplankton cells typically double in numer in a single day; zooplankton have generation times on the order of seven days). If it were assumed that all entrained organisms

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* The extent of the immediate area physically and biologically altered also depends on the width, depth, and velocity gradients of the river. In addition, specific intake and discharge designs will influence the size and shape of the areas affected by intake and discharge flows.

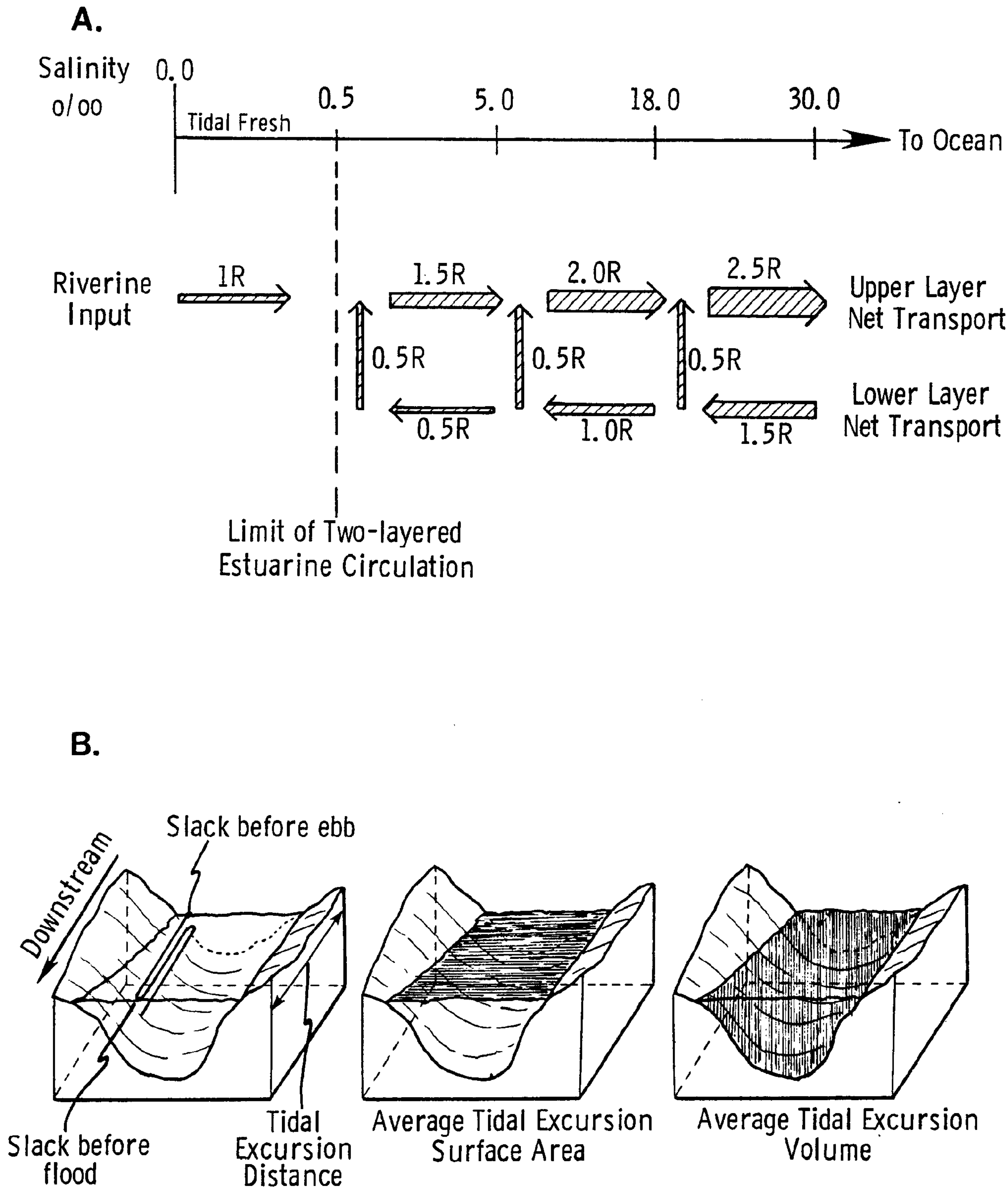

Figure III-4. (A) Estuarine circulation patterns
(B) Tidal excursion

were killed, and that the remaining organisms in the tidal excursion volume continued to be homogeneously distributed (i.e., instantaneously mixed), then the ratio of plant withdrawal volume, during the doubling time, to the tidal excursion volume would represent the percentage reduction in population growth rate attributable to entrainment losses. For populations that are limited in growth due to other factors (such as nutrients), the effect of lowering growth rate by 10-20 percent will probably only affect the time required to reach the limiting level, not the overall standing stock.

Table III-3 and III-4 show these various flows and volumes for plants in Maryland and on Maryland-related water bodies. These areal and volumetric relationships indicate a potential impact of power plants based on scaling alone. Based upon these ratios alone, one would, for example, expect the C.P. Crane, Benning Road, Chalk Point, Buzzard Point, Vienna, and, as a group, the Baltimore BG&E plants, to have a greater potential for aquatic impact. Detailed studies are required, however, to confirm or deny the existence of any in-plant effect.

Having discussed the possible impacts of plants from a physical comparison of the water body size to the plant water needs, we shall now turn to the results of evaluation and monitoring studies for each site within the various salinity regimes.

Mesohaline

This medium salinity zone accounts for the greatest percentage of aquatic habitat in the Maryland portion of the Chesapeake Bay. It serves as the primary area of shellfish and forage fish production, and as nursery and feeding ground of most commercially and recreationally valuable fish species and blue crabs. The three plants located in this zone (Calvert Cliffs, Chalk Point, and Morgantown [summer-fall]) are the largest and newest in the State. All three of these plants have been and are being intensively studied. Preliminary findings of Calvert Cliffs monitoring studies covering the first two years of operation of Unit 1, have been reported (6,7). Morgantown monitoring findings have also been summarized (2,3). Chalk Point was the subject of study in the 1960's (4), and is currently being extensively studied.

- Entrainment

  Inplant losses of about 30-70 percent of entrained zooplankton have been observed at Calvert Cliffs. Loss of entrained phytoplankton have also been observed, primarily in late summer and fall (6,7). In both cases, no nearfield depletion has been observed. Regional reduction in zooplankton density and phytoplankton assimilation was noted in 1975, but the widespread nature of the changes suggest the plant was not the causative agent (6,7).

  High zooplankton mortalities (50 percent) have been measured as a result of entrainment at Morgantown only under the most severe thermal and chlorine stress conditions. Phytoplankton productivity was also reduced during those periods (2). However, no changes in zooplankton and phytoplankton populations in the river were detected (2). It was estimated that 2 percent of the plankton transported

Table III-3. Water flows at Maryland power plants.

	MW Nameplate Rating	Plant Withdrawal (m^3/sec)	Mean River Discharge (m^3/sec)		Root Mean Square Tidal Flow ($10^3 m^3$/sec)		Double Tidal Excursion Distance (Nautical Mi.)	Average Tidal Excursions Volume ($x10^6 m^3$)	Mean of Two Tidal Tidal Excursions Surface Area ($x10^6 m^2$)
			Spring	Fall	Spring	Fall			
Benning Road [a]	749	6.1	6.2	2.4	0.003	0.003	2.1	1.5	1.70
Brandon Shores [b]	1220	0.9	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Buzzard Point	235	3.5	6.2	2.4	0.37	0.37	3.0	9.0	2.10
Calvert Cliffs	1828	156.4	2300.0	400.0	61.40	56.70	11.8	2263.5	250.00
Chalk Point [c]	1387	23.4	20.0	8.0	2.03	1.89	13.1	113.5	45.40
C.P. Crane [d]	400	21.0	0.5	0.5	0.56	0.44		5.0	3.00
Dickerson [e]	588	14.7	358.0	144.0		-	-	-	-
Douglas Point [f]	2200	1.4	451.0	181.0	9.42	8.99	8.1	318.2	79.70
Gould St. (g)	174	67.0							
Riverside (g)	334	13.8							
Wagner (g)	1043	41.6	9.0	3.0	1.80	1.80		486.6	68.00
Westport (g)	194	10.0							
Morgantown	1252	61.1	487.0	197.0	12.40	11.40	11.8	636.0	102.70
Possum Point	478	14.8	475.0	195.0	4.44	4.13	6.6	199.3	37.70
Potomac River	514	9.7	470.0	190.0	1.38	1.20	10.5	50.4	19.75
R.P. Smith [e]	110	3.5	200.0	30.0		-	-	-	-
Summit [f]	900	0.7	96.3 [h]	53.8 [h]	1.27	1.18	20.4	61.6	6.00
Vienna [i]	230	3.7	4.3	1.4	1.74	1.62	19.7	54.0	15.50

(a) 250 MW with cooling towers

(b) Withdraws cooling water from Wagner discharge canal, uses cooling tower

(c) Units 1 and 2 have once-through cooling, Unit 3 has cooling tower (withdrawal not including augmentation pumps)

(d) Withdraws from Seneca Creek, discharges into Saltpeter Creek

(e) River plant

(f) Proposed plants, with cooling towers

(g) Total for the four plants

(h) Based on net non-tidal transport through C & D Canal

(i) Units 5, 6, 7 have once-through cooling systems

Table III-4. Relationships between plant withdrawal volumes and tidal volumes; plant withdrawal rate and tidal and river flow rates.

	$\frac{VP_1}{VT}$ %	$\frac{VP_7}{VT}$ %	$\frac{QP}{QT}$ %		$\frac{QP}{QR}$ %	
			Spring	Fall	Spring	Fall
Benning Road (a)	35.1	246.0	203.33	203.33	98	254
Brandon Shores (b)	N/A	N/A	N/A	N/A	N/A	N/A
Buzzard Pt.	3.4	23.5	0.95	0.95	56	146
Calvert Cliffs	0.6	4.2	0.25	0.28	7	39
Chalk Pt. (c)	1.8	12.5	1.15	1.24	117	293
C.P. Crane (d)	36.3	254.0	3.75	4.77	4200	4200
Dickerson (e)	N/A	N/A	N/A	N/A	4	10
Douglas Pt. (f)	< 0.1	0.3	0.01	0.02	< 1	1
Gould St., Riverside, Wagner, Westport (g)	1.3	9.0	4.00	4.00	801	2403
Morgantown	0.8	5.8	0.49	0.54	13	31
Possum Pt.	0.6	4.5	0.33	0.36	2	5
Potomac River	1.7	11.6	0.70	0.81	3	8
R.P. Smith (e)	N/A	N/A	N/A	N/A	2	12
Summit (f)	0.1	0.7	0.06	0.06	1 (h)	1 (h)
Vienna (i)	0.6	4.1	0.21	0.23	86	264

Key:

VP_1 = plant withdrawal volume - 1 day
VT = tidal volume
VP_7 = plant withdrawal volume - 7 days

QP = plant withdrawal rate
QT = tidal flow
QR = flow of river (or net flow up estuary)

NOTE: For footnotes, see Table III-3

past the plant would be destroyed by entrainment (2,3). No adverse impact would result from losses of this magnitude to the rapidly reproducing plankton populations.

Large kills (up to 100 percent) of entrained organisms have been observed at Chalk Point* with thermal and biocide stresses appearing to both be important as causes. Near-plant depletions of jellyfish were noted, but no changes in river populations of copepods were found (4).

The findings at all three plants are consistent. Entrainment losses of phytoplankton and zooplankton do occur but high reproduction rates of the affected populations compensate for plant effects. Cumulative effects would not be expected. Studies to verify this are now underway.

Chalk Point has an additional entrainment effect due to the lack of screens in front of the augmentation pumps used during the summer months. Without these screens, fish and crabs that would normally be impinged may be entrained into the pumps. Studies to quantify the magnitude of these losses are now in progress (9).

Eggs and larvae of Bay anchovy, naked goby and hogchoker (all forage species) are found in the Calvert Cliffs vicinity and are entrained. Densities near the plant have not differed significantly from those observed beyond the area of plant influence (6). Thus, nearfield losses caused by entrainment were not detected. The same species of larvae are found at Chalk Point and Morgantown. Nearfield ichthyoplankton depletions were also not detectable at Morgantown (2). Localized losses of ichthyoplankton of these species, which spawn virtually throughout the Maryland portion of the Bay, are insufficient to decrease Bay populations.

- Impingement

Fish and crab impingement data from Calvert Cliffs, Morgantown and Chalk Point are summarized in Table III-5. Menhaden and spot dominate the fish impingement at these plants, except for Calvert Cliffs impingement in 1975 which shows greater variability in species composition. The six species listed in the table are all abundant, ubiquitous species that occur throughout mesohaline regions of the Bay and its tributaries. These species also dominate net catches made during surveys conducted at these sites (3,6), confirming the non-selective nature of cropping by power plants. The plants appear to be impinging fish at a rate proportional to their abundance in the plant vicinity. There is insufficient knowledge of population size and dynamics of all of the listed species to predict the exact consequence of plant-induced losses, but no changes in fish density or community composition in the vicinity of these plants have been observed. This implies that impingement losses are too small to significantly alter the size of Bay populations. One way of putting impingement losses in perspective is to compare them to other population

* PEPCO has indicated that more recent, unpublished studies may lower entrainment mortality estimates (8).

Table III-5. Estimated total impingement by species at mesohaline power plants (number of individuals). Data have been obtained by summing monthly totals estimated from samplings during that month. Sampling schedules (frequency and duration) vary from plant to plant and from time to time. (See references for details.)

	1975		1976			
Species	Morgantown[a]	Calvert Cliffs[b]	Calvert Cliffs[b]	Chalk Point[c]	Morgantown[d]	Total[e]
Menhaden[f]	414,376 (57%)	189,873 (11%)	454,209 (20%)	552,782 (59%)	759,680 (55%)	1,766,671 (39%)
Spot[f]	200,972 (27%)	261,964 (15%)	1,280,094 (58%)	254,404 (27%)	286,869 (21%)	1,821,367 (40%)
Hogchoker	2,510 (0.3%)	99,154 (6%)	188,367 (8%)	50,893 (5%)	36,167 (3%)	275,427 (6%)
Bay Anchovy	30,969 (4%)	672,709 (38%)	77,271 (3%)	10,421 (1%)	47,851 (3%)	135,543 (3%)
Croaker[f]	3,069 (0.4%)	338,531 (19%)	106,799 (5%)	5,102 (0.5%)	--	111,901 (3%)
White Perch	60,648 (8%)	3,921 (0.2%)	4,752 (0.2%)	4,365 (0.5%)	96,993 (7%)	106,110 (2%)
Others	19,576 (3%)	199,050 (10.8%)	111,881 (5%)	59,030 (7%)	147,721 (11%)	318,632 (7%)
TOTAL FISH	732,081 (100%)	1,765,202 (100%)	2,223,373 (100%)	936,997 (100%)	1,375,281 (100%)	4,535,651 (100%)
Crabs	--	294,975	434,004	1,106,269	280,704	1,820,977

(a) March and June-December (6)

(b) January - December (7)
(Does not include large episodic fish kills - see text)

(c) June - December

(d) May 15, 1976 - May 28, 1977 (6)

(e) For periods indicated

(f) Predominantly juveniles

losses (i.e., due to predation, fishing, natural die-offs, etc.). Such data are available for the major impinged species discussed below. Detailed studies are now in progress to improve our knowledge of these species.

-- Menhaden is one of the major commercial finfish species in the Bay, usually accounting for over 40 percent of total landed weight (Table III-6). Populations are mobile, and they are distributed throughout mesohaline and oligohaline regions of the Bay. In some cases, the impingement data in Table III-5 do not span an entire year, but do cover the summer-fall period when menhaden are most abundant. Impingement mortality for menhaden is considered to be 100 percent. As an approximation of a single year's impingement weight total of menhaden for the 3 mesohaline plants, the 1976 number totals were multiplied by the average weight of menhaden impinged at Calvert Cliffs (20 g = .043 lbs) to give total impinged weight estimates of 76,000 pounds. This is about 1.25 percent of the 1976 Maryland landings of 6 million lbs (Table III-6). Although the mean weight of commercially harvested menhaden is not known, they are larger (older) than the juveniles being impinged. The number of juvenile menhaden impinged is, therefore, much more than 1 percent of the number of adult menhaden commercially caught. However, since these juveniles would have suffered considerable natural mortality (typically 90 percent) before reaching harvestable size, the plant related losses would probably cause a much smaller decline in subsequent years.

Menhaden experience large natural die-offs throughout the Bay during summer months. Many of these kills are unreported or unquantified. Reported kills of menhaden in 1974 and 1975 totaled 100 million and 1.9 million individuals, respectively (10). The 1976 impingement total for the 3 plants is estimated to be 1.8 million individuals.

Menhaden are also a favorite prey of the two major predatory fish in the Bay: bluefish, and striped bass. Daily rations for these species are about 3-5 percent of their body weight/day (11). Total stock of bluefish and striped bass in the Bay is unknown, but the amount harvested, which may represent only a small percentage of the stock, can be used to give some insight into the amounts of forage fish consumed by predators. From May to October in 1976, sportfishermen landed 535,800 lbs of striped bass and 2,915,179 lbs of bluefish in the upper Bay (12). If these totals are combined with commercial landings over the entire Bay during the same period, total weight of both species landed was 5,246,000 lbs. Assuming 4 percent of body weight consumed each day for a 5 month period, total forage which would have been utilized by these landed fish is 32,525,000 lbs, much of which would have been menhaden. The estimated impinged total of 76,000 lbs is about 0.23 percent of that total. All of the above comparisons demonstrate that menhaden impingement kills represent a small perturbation on the Bay.

-- Spot and croaker juveniles are abundant in mesohaline areas. Their impingement mortality is considered to be near 100 percent (13).

Table III-6. Maryland commercial landings

	1972		1973		1974		1975		1976	
	Pounds	Dollars	Pounds	Dollars	Pounds	Dollars	Pounds	Dollars	Pounds	Dollars
Fish										
Alewives[a]	1,654,641	$ 33,098	2,331,424	$ 45,254	1,387,676	$ 31,801	696,477	$ 16,075	121,990	$ 5,320
Bluefish	59,075	5,802	275,330	23,097	372,738	28,357	271,914	25,671	489,399	28,589
Catfish and Bullheads	386,340	39,567	295,083	31,125	302,628	37,908	260,050	30,485	230,023	28,409
Eels	229,764	33,164	180,466	44,118	144,527	42,984	204,667	69,725	165,725	58,004
Menhaden	6,212,002	124,614	9,686,956	221,059	4,932,962	128,631	6,228,700	166,003	6,105,600	192,607
Sea Trout	313,428	34,125	539,520	74,615	372,832	47,754	892,718	79,414	428,786	46,283
Shad[a]	954,145	117,299	597,914	105,573	221,444	46,000	182,352	44,606	110,639	42,028
Spot	68,171	10,974	27,322	5,244	10,018	1,383	89,900	8,314	15,737	2,838
Striped bass[a]	3,185,929	917,548	4,677,617	1,451,800	3,382,852	880,329	2,763,509	1,083,710	1,813,910	990,863
White perch[a]	1,108,033	204,784	762,719	162,697	497,755	93,402	568,900	112,049	407,700	107,046
Yellow perch	101,465	13,549	35,523	7,150	35,409	5,070	29,818	5,323	22,744	4,973
Other finfish and Unclassified	897,610	185,717	1,179,483	246,222	1,602,952	277,375	2,785,551	510,279	3,714,130	805,787
TOTAL FISH	15,170,603	$1,720,241	20,589,357	$2,417,954	13,263,793	$1,620,994	14,974,556	$2,152,095	13,626,383	$2,312,747
Anadromous fish above and % of total fish		$1,272,729 (74%)		$1,765,324 (73%)		$1,051,532 (65%)		$1,256,440 (58%)		$1,145,257 (50%)
Shellfish										
Blue crabs (hard, soft, peeler)	25,050,531	$3,114,209	20,723,286	$3,484,057	24,973,677	$4,631,815	25,917,890	$5,149,768	20,885,600	$5,649,968
Soft clams	1,949,520	1,014,782	668,688	557,240	1,766,136	1,501,210	1,246,128	1,174,340	1,742,604	2,767,698
Oysters	19,052,800	11,963,272	19,055,700	12,561,489	17,263,970	11,588,664	16,402,300	13,126,666	15,827,708	16,428,117
Turtles (snapper)	18,023	3,597	24,353	5,189	36,540	10,226	83,144	26,644	48,085	14,136
Terrapin (Diamondback)	3,545	1,523	1,458	709	1,733	1,016	5,058	3,319	1,201	791
ABOVE SHELLFISH[b]	46,074,419	$16,097,383	40,473,485	$16,608,684	44,042,056	$17,732,931	43,654,520	$19,472,737	38,505,198	$24,860,710
GRAND TOTAL	61,245,022	$17,817,624	61,062,842	$19,026,638	57,058,849	$19,353,925	58,629,076	$21,624,832	52,131,581	$27,173,457

(a) Anadromous species

(b) Exclusive of the following species limited primarily to Atlantic Ocean waters: lobsters, hard and surf clams, conch, and squid.

Source: "Maryland Landings," Current Fisheries Statistics, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service, December 1973-76.

The estimated annual impingement in 1976 at Morgantown, Chalk Point, and Calvert Cliffs was about 1,800,000 spot and 112,000 croaker with mean weights of 0.0112 and 0.018 lbs, respectively. Trawl surveys at Morgantown and Calvert Cliffs show that both spot and croaker juveniles are very abundant in these areas. We estimate, from catches at Calvert Cliffs, that the total number of spot impinged in June 1976 (346,800, the highest monthly total for the year) was equivalent to the number of spot occupying about 100 acres of Bay bottom at that time, representing approximately 0.01 percent of the suitable habitat in the Bay (14). Another indication of the density that occasionally occurs is that 23,000 juvenile spot were taken in a single tow in the fall of 1976 during the scientific sampling program.

To determine the impact of this impingement, we can compare to sports and commercial catches. In making such a comparison, it must be kept in mind that the juveniles impinged in the lower mesohaline habitats (e.g., Calvert Cliffs) would have spend their adult life in a region extending from the higher mesohaline environment at the Maryland-Virginia border to the marine environment of the ocean. Thus, any effect of juvenile kills at Calvert Cliffs would manifest itself in depletions in the lower Bay and the ocean. Because of relatively high natural mortality in developing from juveniles to adults, the effect of juvenile impingement mortalities would be greatly attenuated as it propagates through the age structure of the species. It must also be kept in mind, that both spot and croaker are very lightly exploited resources in Maryland, with modest sports and commercial catches.

The available data (12) indicates that the sport harvest in the upper Bay during May through October 1976 was about 52,800 spot and 10,950 croaker of an average weight of 0.3 to 0.1 lb, respectively (clearly a different age class from the impinged fish). These low numbers are reasonable, considering the preference of the adult fish for higher salinity waters. Commercial landings in the Bay for 1976 were 5,723 lbs in Maryland and 1,203,766 lbs in Virginia for spot, and 1,089 lbs in Maryland and 2,871,420 lbs in Virginia for croaker (Table III-6). (Total Maryland commercial landings in 1975, mainly from the ocean, were 89,900 lbs and 639,000 lbs for spot and croaker, respectively.) Converted to number of individuals, the Bay commercial catch of 4 million spot and 3.2 million croaker can be compared to an estimated adult stock loss 0.22 million spot and 0.012 million croaker due to impingement (assuming 10 percent of juveniles survive to adulthood).

The conclusion is that the juvenile impingement losses of spot and croaker, lightly exploited species, are insignificant, based on the great abundance of these juveniles in the mesohaline habitat.

-- Hogchoker, a very hardy species, suffer less than 1 percent mortality as a result of being impinged. Thus, no plant influence on hogchoker populations can be expected.

-- Anchovy, the remaining major impinged fish species, is distributed throughout the Bay. Acoustic surveys have revealed densities on the order of 7-25 fish per m^3 of water (6). At a density of 13-14 fish per m^3, the total impinged in one year at the three plants would occupy only about 10,000 m^3 (a volume approximately 100 by 100 feet wide and 30 feet deep), 1/4 of 1 percent of the total mesohaline volume of the Bay. Impingement mortality is 100 percent (13).

-- Crabs are impinged at all 3 plants. In 1976, Morgantown impinged about 281,000 crabs. From June to December 1976, Chalk Point impinged approximately 1 million crabs,* which was 3 times the commercial catch in the Patuxent and equal to the estimated sport harvest. In 1976, Calvert Cliffs impinged approximately 440,000 crabs. Mortality studies have demonstrated that crabs suffer less than 1 percent mortality from impingement (13). Thus, unless the crabs should suffer delayed mortality as a result of the impingement episode (and there is no evidence of this), no impact would result from the mechanical effects of impingement. Post-impingement mortalities could occur where crabs are washed into a discharge canal (such as at Chalk Point or Morgantown) where they are exposed to chlorinated and heated effluent. This possibility is currently being assessed at Chalk Point.

The impingement rate at the Calvert Cliffs plant has changed considerably since the first summer of operation. During July/August 1975, several large impingement episodes of 500,000 fish or larger crushed intake screens and forced shut-down of the power plant (7). It was theorized that entrapment (explained previously), coupled with low DO caused by certain wind conditions weakened the fish, causing them to impinge in large numbers. To combat this problem, BG&E now removes four panels from the curtain wall during the summer months, allowing surface water (presumably higher in oxygen) to enter and allowing an escape route for the fish. Since this adjustment, only one large episode has occurred: during routine impingement studies at the plant on June 13, 1978, approximately 72,000 fish were collected during one hour (15).

- Discharge Effects and Habitat Modification

The thermal plume produced by Calvert Cliffs Unit 1 averaged 10 acres within the 2°C excess temperature isotherm (6). The maximum extent of this isotherm along the Bay was 2/5 mile from the point of discharge (approximately 1/10 the width of the Bay at that point). In studies of fish, plankton and benthos, no changes in community composition or abundance could be found which were attributable to this thermal influence. Benthic communities were altered only in about a 60-acre bottom area from which loose sediments have been swept by the high velocity discharge. No deleterious effects on oyster growth or mortality nor uptake of copper by oysters were observed (6).

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* Based on extrapolation of impingement data taken during 465 half-hourly sampling periods from June through December. The utility (PEPCO) feels that a saturation effect may limit the number of crabs impinged during actual operation.

The thermal plume produced by Calvert Cliffs Unit 1 and 2 combined averaged 30-40 acres within the 2°C excess temperature isotherm and occasionally exceeded 60 acres in size (16). Studies to quantify any discharge effects are presently in progress.

Morgantown findings are consistent with Calvert Cliffs results. The thermal plume as defined by the 2°C isotherm, was generally about 3-4 acres in size, but occasionally as great as 80 acres. No significant influence of this thermal discharge has been found (3).

Temperature elevations caused by Chalk Point operations have been detected over 1 mile from the plant (17). Because the estuary is shallow and has low flows (Table III-4), thermal influence would be experienced over greater areas than at Calvert Cliffs or Morgantown. Despite this fact, the monitoring studies conducted in the 1960's revealed few plant effects. Erosion of copper from condenser tubes was noted, and uptake of copper discharged from the plant by oysters was found. This situation was apparently corrected later (18) Large concentrations of fish in the discharge canal have appeared in fall and winter, and the area now supports an intensive sport fishery. Large kills of fish and crabs in the discharge channel were reported in the 1960's, attributed to accidental excessive discharge of chlorine (4,19). Similar kills have not been reported in recent years, and no detectable effects on zooplankton or ichthyoplankton were found. Additional monitoring is currently proceeding at this plant.

When results of studies at the three plants are compared, a consistent picture emerges indicating low probability of cumulative impact on the mesohaline environment. Plankton entrainment losses have been measured inside several of the power plants. These losses, however, do not show up as any measurable plankton depletion in the waters around the plant. This lack of measurable effects is probably due to the high reproduction rate of the plankton, and indicates that there is no impact due to plankton entrainment. No important commercial or recreational species spawn in this habitat, and entrainment losses of ichthyoplankton are thus of little significance. Localized effects on benthic organisms, including shellfish, are sometimes evident. These effects have no significance beyond the immediate discharge areas.

Tidal Freshwater/Oligohaline

These habitat zones have significant value as the major spawning area of anadromous fish, which as a group have accounted, on the average, for about 65% of total monetary value of commercially harvested finfish from 1972 to 1976 in Maryland (Table III-6). Anadromous spawning occurs in spring so the plants of most concern are those in the tidal fresh zone at that time (Table III-2). The nine plants so located can be divided into three geographical regions.

The Baltimore Plants (C.P. Crane, Gould St., Riverside, H.A. Wagner, and Westport) are located on the Patapsco River and its tributaries and on Seneca Creek. In the past, environmental degradation which is not related to these plants has eliminated the area as an important anadramous spawning ground (20), and the area also does not serve as a major nursery area for juveniles of most important fish species. White perch is the most common fish. With the exception of Wagner and Crane, these plants are all older than 20 years, are used for peaking service, and have seen decreased service since Calvert Cliffs came on line.

The Washington Area Plants (Benning Road, Buzzard Point, and Potomac) are located in the upper Potomac Estuary where chronic oxygen deficiencies have been reported (21). This decline in water quality has been reflected in a reduction in diversity and abundance of fish (22). However, if the other pollution sources should be cleaned up, and these areas became productive again, power plants should not be allowed to adversely affect the environment. Thus, assessment of the potential impact of these plants is appropriate despite the present absence of major aquatic resources nearby.

The Possum Point plant is located in a segment of the Potomac River where striped bass spawn, and Douglas Point located across the river is a proposed site for a new power plant. The proposed plant, the effect of which has been extensively studied, would utilize cooling towers so that cooling water withdrawals would be small (estimated 50 cfs) (23). Another plant, Summit, has been proposed in New Castle County in Delaware on the Chesapeake and Delaware Canal, approximately two-thirds of the way towards the eastern end of the canal. This plant, as originally proposed, would use 2 cooling towers and have a total withdrawal rate of 42.5 cfs.

The oligohaline zone serves as a nursery area for many estuarine fish during much of the year. Some striped bass spawning occurs in portions of this zone in the spring. The three plants using oligohaline waters for cooling in the spring are Chalk Point on the Patuxent, Morgantown on the Potomac and Vienna on the Nanticoke. The salinity Chalk Point is often on the borderline between oligohaline and mesohaline in the spring and the Morgantown site drops to within the oligohaline range on the average only during spring of each year (2). Thus, impact at Chalk Point and Morgantown were discussed under mesohaline plants, with only Morgantown ichthyoplankton entrainment and impingement mentioned here.

Eight of the ten freshwater tidal plants become oligohaline during the summer-fall period (Table III-2).

- Entrainment

  Plankton entrainment data are not available for any of the present tidal freshwater plants. Studies elsewhere (see Mesohaline discussion above) indicate that entrainment losses of phytoplankton and zooplankton generally do not result in detectable nearfield depletions and thus would be unlikely to contribute to cumulative impact. However, at most of the present tidal fresh plants, cooling water withdrawal is large relative to freshwater and tidal flow (Table III-4), and localized effects on plankton may occur. Entrainment losses of ichthyoplankton could cause declines in fish populations utilizing discreet spawning areas. The Baltimore and Washington areas currently do not serve as important spawning ground for any anadromous species. The abundant species of these areas, such as white perch, are ubiquitous in the Bay (14). Losses of eggs and larvae at those plants are unlikely to cause Bay-wide declines in such ubiquitous stocks. Possum Point, however, is sited on the striped bass spawning grounds in the Potomac estuary. Recent work indicates that the plant entrains a maximum of about 2 percent of the bass larvae produced annually in the Potomac The exact significance of such a loss to adult fish is not currently known, but it can certainly not exceed 2 percent of the actual catch of fish spawned in the Potomac (23).

If a plant using cooling towers were constructed at Douglas Point (across the Potomac from Possum Point) it would be unlikely to alter local zooplankton and phytoplankton populations through entrainment because of the small volume of water utilized. It has been estimated that such a plant would entrain between 0.6 and 1.2 percent of the striped bass larvae produced there in any one year. Such a loss could cause no more than similar percentage decline in eventual production of adults (23). The strength of the year class is usually well established by the time the striped bass spawn become juveniles (3-5 months old) and is largely dependent on environmental conditions during that period (24). The Summit plant is located in an area of some striped bass spawning, although most of the spawning takes place towards the western end of the canal. It is estimated that between 1 and 2 pecent of the entrainable striped bass ichthyoplantkon that originate in the canal will be entrained by the Summit power plant (25). Possible plant design alternatives to reduce the entrainment are still being pursued.

Morgantown is located 20 km downstream of the center of the striped bass spawning area in the Potomac. Few eggs or larvae ($\leq$ .01 percent) are entrained (26) and consequently, no significant impact on the striped bass population occurs because of the operation of this plant. Vienna is in the midst of the spawning area in the Nanticoke. The plant has two distinct sections: units 5, 6, 7 (68 MW) using once-through cooling (withdrawal 3.6 m^3/sec) and unit 8 (162 MW) using a cooling tower (withdrawal 0.12 m^3/sec from discharge of units 5, 6, 7). The once-through units, now scheduled for retirement in 1987, will operate below 25% capacity factor (annual average) after 1980 (27). In addition, Delmarva has proposed a 400 MW expansion (1987 completion date) that will withdraw 0.36 m^3/sec for cooling and plant purposes. The present plant does entrain striped bass eggs and larvae (28), but the exact magnitude and consequences of the losses are not known. To estimate the loss, we may use two simple techniques (29) involving tidal volumes and known distributions of eggs and early larval stages. These results, for a withdrawal rate of 0.36 m^3/sec (about 10% capacity factor for units 5, 6, 7), give an entrainment estimate of 3-8% of the spawn in the river.* Spring capacity factors for the last 5 years have ranged between 23% (1977) to 79% (1974). The assumptions implicit in this simple calculation are probably not valid for losses greater than

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* Implicit in this calculation are the following assumptions: 100% mortality, no recirculation, uniform entrainability for 90 days.

30%*. Nevertheless, they do show that entrainment losses at this site constitute a significant percentage of the Nanticoke spawn. Studies now underway to evaluate the impact of the new unit at Vienna will be used to establish the impact of the present units. A possible outcome of this study will be a capacity factor limitation at this site during the spawning and nursery season for striped bass.

The potential impact on the overall striped bass stock can be estimated by examining the contribution of each impacted area to total spawning in the Maryland part of the Chesapeake Bay and its tributaries. These contributions can be estimated from the commercial catch records for the months (March and April) just prior to spawning. This catch is assumed to be proportional to the presence of spawning adults and hence to the spawn. This data is summarized in Table III-7 which shows, for example, that Potomac River spawning constitutes about one fourth of total striped bass spawning in Maryland. Therefore, under our assumption, a 1 percent loss of striped bass larvae in the Potomac would translate to a 0.25 percent loss of the Maryland fisheries. The total potential loss can be assess from the size of the fishery affected. Table III-6 shows the annual commercial striped bass catch in Maryland (the average annual sports catch is roughly equal to the commercial catch (12)). Following the reasoning above, each 1 percent loss of the striped bass larvae in the Potomac is equivalent to a loss of about 8000 lbs of striped bass. This calculation neglects the relative decline in the Potomac catch for 1964 to 1972 (Table III-7) as well as the absolute decline in Maryland catch (Table III-6). In addition, the Bay stock is the principal contributor to a large fishery in the mid-Atlantic states and New England.

- Impingement

No impingement data are available for the the tidal-fresh plants. Since all except Possum Point are sited on waters of degraded water quality supporting limited fish populations, any impingement losses from these plants have little probability of influencing Bay resource yields. Because of the low velocity and volume of cooling water to be utilized at the proposed Douglas Point plant, magnitude of impingement there would be expected to be low and impact inconsequential (23).

It is interesting to note that the majority of white perch collected (3) in Morgantown impingement samples in 1975 (Table III-5) were taken during the single spring sampling period (March). At that time salinities are close to oligohaline. This species is more typically oligohaline than mesohaline. Thus, the data substantiates the validity of examining cumulative plant impact according to habitats defined by salinity regimes. As discussed earlier, white perch populations occur in virtually all tributary estuaries of the Bay, including areas of poor water quality. Morgantown impingement kills are not expected to modify Potomac River or Bay white perch populations. No impingement data is available from Vienna.

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* Which would occur at a capacity factor of 37-100%.

Table III-7. Commercial catch of striped bass in March and April by region in the Maryland portion of the Chesapeake Bay, by percent

Year	Upper Bay above Sassafras River	Bay Bridge to Sassafras River	Chester River	Cove Point to Bay Bridge	Choptank River	Virginia to Cove Point	Patuxent River	Nanticoke River Wicomico River	Potomac River (including Virginia side)
1972	8.67	30.76	4.61	5.76	10.02	2.37	2.22	15.87	19.67
1971	10.13	27.24	2.39	5.66	10.58	0.85	4.07	13.15	25.87
1970	9.37	34.86	5.18	4.90	10.84	0.99	2.65	8.81	22.14
1969	17.17	33.66	1.63	4.18	9.24	0.86	3.27	8.27	21.67
1968	12.04	24.20	1.76	3.69	6.40	1.25	2.09	11.61	36.74
1967	9.54	29.58	1.36	3.31	7.00	0.82	2.18	11.45	34.75
1966	6.03	22.91	2.73	2.84	10.37	1.65	1.07	19.34	33.03
Averages	10.73	29.50	2.80	4.30	9.10	1.25	2.49	12.28	27.46

* Discharge and Habitat Modification

  The general degradation of water quality in the vicinity of the Baltimore and Washington plants (21) makes identification of plant discharge effects difficult. If water quality were to improve, thermal and biocide discharges of these plants would have the same potential for aquatic impact as plants in unpolluted areas. Thus, they require studies to determine appropriate measures to mitigate any adverse impact. (Studies at the Baltimore plants are now underway.) Possum Point cooling water enters the Potomac shortly after discharge. At the proposed Douglas Point plant, the discharge would consist of cooling tower blowdown, which could contain biocides and metals such as copper corroded from the plant cooling system, unless, as recommended, titanium tubing is used in the condenser and the blowdown is dechlorinated (30). Because of the low volume of discharge, any effects of these discharges would be restricted to the immediate area of the discharge point. Studies of the Vienna discharge during spring (31) revealed a small plume confined near the west bank. Over most of the region, larger temperature gradients resulted from differential solar heating than from the heated water discharge.

Riverine

The only Maryland steam electric stations located on rivers are R.P. Smith and Dickerson, both on the Potomac. Each utilizes, at times, a substantial portion of average river flow for cooling purposes (Table III-4). The plants are relatively old, of low to medium generating capacity, and located in areas inhabited by typical warm water "riverine" biological communities (32).

* Entrainment

  Riverine communities are not plankton-based. Entrainment losses of the sparse populations of plankton present have little influence on local ecosystems. No spawning of anadromous fish occurs near these plants. Most resident fish are nestbuilders having non-planktonic larvae. Significant ichthyoplankton entrainment would thus not occur. The juveniles tend to be shore oriented, not moving with the main flow of water (33).

* Impingement

  Data are now being gathered to provide the basis for an analysis of impingement effects.

* Discharge and Habitat Modification

  Temperature elevations in the discharge area are usually the only type of interaction of importance in assessing impact on riverine aquatic communities. Data delineating the size of the thermal plumes has been collected, but the results are not yet available. Studies to assess the significance of these elevations and to quantify their areal extent are underway at both plants.

The Conowingo Dam on the Susquehanna River is the only large hydroelectric generating station in Maryland. Large kills of anadromous clupeid fish (alewives, blueback, American and hickory shad) occurred at the base of the dam in the 1960's, and were accompanied by declines in the size of the annual runs of these species (34).

These springtime kills of spawning fish occurred when the turbines were shut off at night, and no water passed the dam site. The cause of the mortality was traced to a depletion of dissolved oxygen by fish massed at the foot of the dam during spawning runs (34). No kills have occurred in recent years since an agreement between the utility and the Maryland Department of Natural Resources went into effect, guaranteeing a continuous minimum flow of 5,000 cfs through the dam during the spawning season.

Runs of anadromous fish in the Susquehanna below the dam have continued to decline. However, since kills have not occurred in the dam, the decline cannot be directly attributed to these kills (34,35).

D. Regulatory Considerations

The question of which type of cooling system should be required for existing power plants in order to ensure acceptable aquatic effects has been the subject of several State and Federal Regulations. Under the Federal Water Pollution Control Act of 1972 (FWPCA), a goal of zero heat discharge was set by Congress. The original proposed EPA regulations under this Act (March 1974) included a requirement for all "base load" steam electric stations to install closed cycle cooling (see Chapter IV) by 1978/79. Exceptions were to be granted under section 316(a) if a utility could demonstrate that closed-cycle cooling was not needed to "assure the protection and propagation of a balanced indigenous population of shellfish, fish, and wildlife in and on the body of water..." The promulgated regulations have changed the deadline to 1981 for units constructed after 1970. However, the entire issue of federal regulation has been clouded by a 1976 court decision remanding several sections of the EPA regulations that affect Maryland power plants (36). In addition, the lack of final format for regulations, guidance manuals, and procedures has hindered initiation of studies. On the State level, the Water Resources Administration (WRA) has been delegated authority under the FWPCA to administer the National Pollutant Discharge Elimination System (NPDES). Under this system, once the State has established water quality standards that are at least as strict as Federal regulations, the State may, with EPA oversight, regulate all discharges within the State. Water Resources Regulation 08.05.04.13 places requirements on all steam electric stations over 25 MW expected to have in 1980 an annual capacity factor over 25 percent or a summer capacity factor over 40 percent. All discharges that do not satisfy a preliminary screening test based on the ratio of the size of the thermal plume to the cooling water body and the importance of spawning in the region must either: 1) install closed cycle cooling; 2) demonstrate that the standards are unnecessarily stringent and existing conditions preserve natural water quality; or 3) demonstrate that other limitations less costly than closed cyle cooling will preserve natural water quality. The first case (Morgantown) is presently scheduled for the spring of 1979.

All steam electric stations must, under section 316(b) of the FWPCA, demonstrate best practicable technology (to minimize impact) in their intake structure design. However, the EPA regulations for this section have also been remanded (36). Maryland Water Resources Regulation 08.05.04.13 requires evaluation of best practicable intake structure design by setting up a cost-benefit analysis approach for modifications. Here the potential conflict between Federal and State regulation is minimal.

E. Conclusions and Summary of Impact

Dividing the aquatic habitat into three general areas, we can draw the following conclusions:

- Mesohaline

  Because of the high reproduction rates of the plankton and good tidal mixing at the existing plants, depletion of plankton populations has not occurred. Spawning occurs throughout the Bay for the species of fish present here, so local depletions are insufficient to decrease Bay populations. Impingement totals are small compared to mortality due to other sources. In addition, efforts to reduce these totals are now underway at all three existing plants. Habitat modification effects, usually more subtle in nature, have minor, localized impacts as described in this chapter. Coupled together, the power plant monitoring studies show a low cumulative impact on the mesohaline environment.

- Tidal Fresh/Oligohaline

  The major area of concern within this region is the impact of cooling water withdrawals upon the nursery and spawning areas of striped bass and other anadromous species. Possum Point and Vienna have the highest potential for impact. New facilities planned for this region (Douglas Point, Summit, and Vienna) would increase withdrawals. Using Table III-7 as a guide for the relative importance of striped bass spawning areas, the present and future entrainment levels are summarized in Table III-8. As can be seen, the overall impact upon striped bass due to entrainment drops from an estimated 6.60 percent entrainment (upper bound) of the eggs and larvae spawning in Maryland portion of the Bay to an estimated 3.14 percent (upper bound). The addition of Douglas Point and Summit is more than off-set by the retirements of the once-through cooling units at Vienna. No impingement data is available at any of the present plants; however, degraded water quality at the Baltimore and Washington plants appears to have severely restricted fish populations in these waters. Similarly, habitat modification effects or depletion of plankton would be difficult to detect. Ongoing studies should help to quantify these effects at the Maryland plants. The proposed plants are expected to have no major impacts in the areas of impingement or habitat modification due to the small amount of water withdrawn.

Table III-8. Estimated upper limit impact on striped bass ichthyoplankton power plant entrainment

Power Plant	River	% of Md. Spawn in River	Present to 1980		1980 to 1987		After 1987[a]	
			% of River Population Entrained	% of Total Md. Spawn Entrained	% of River Population Entrained	% of Total Md. Spawn Entrained	% of River Population Entrained	% of Total Md. Spawn Entrained
Possum Pt.	Potomac	28	2	0.60	2	0.60	2	0.60
Morgantown	Potomac	28	0.01	<0.01	0.01	<0.01	0.01	<0.01
Vienna	Nanticoke	12	50[b]	6.00	25[c]	3.00	2.8[d] 8.0[e]	0.34 0.96
Douglas Pt.	Potomac	28	--				1.20	0.34
Summit	C&D Canal	30	--				3	0.90
TOTAL of Md. spawn entrained at all plants				6.60		3.60		3.14

(a) Assuming Douglas Point, Summit, and Vienna unit 9 come on line
(b) Assuming 50 percent capacity factor on once-through cooling units
(c) Assuming 25 percent capacity factor on once-through cooling units
(d) Assuming once-through units retired, Vienna 8 still on line
(e) Vienna unit 9

- Riverine

No impact is expected from entrainment and impingement. Studies of possible habitat modification due to the discharge of heated effluent are now underway at both of the two existing plants in this region. These studies are expected to be completed during 1978.

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CHAPTER IV

RADIOLOGICAL EFFECTS

The first Cumulative Environmental Impact Report has presented a discussion of general siting, safety and health issues pertinent to nuclear power plants. It also presented projections of radiological impacts in Maryland, based upon the utility companies' projections for additional nuclear plants, as delineated in their 1975 Ten Year Plans.

Since 1975, extensive changes have occurred in the utility companies' scheduling for new generation. In addition, the Calvert Cliffs Nuclear Power Plant has commenced operation, providing an opportunity to compare actual impact measurements with preoperational predictions.

This Chapter summarizes the current planning for additional nuclear power in Maryland and focuses on the operations to date at Calvert Cliffs. The quantities of electrical energy produced, effluents released and wastes created are discussed. Results of radiological environmental monitoring activities are presented and radiation doses from plant operation are estimated. Comparisons are made, where appropriate, to regulatory limits and to predictions made prior to reactor start-up. Emphasis is placed on continued compliance with NRC guidelines for keeping radiation doses to the public "as low as reasonably achievable". Finally, radiation doses from plant operations to date are compared to variations in natural dose levels measured in Maryland, and the health risks from low level dose increments are tabulated.

A. Status of Nuclear Power in Maryland

The Calvert Cliffs Nuclear Power Plant, owned by the Baltimore Gas and Electric Company, is the only operating nuclear power plant in Maryland. Each of its two units has a Pressurized Water Reactor licensed at 2700 MW (thermal), with design net electrical power output of 845 MWe. Present ratings are 820 MWe for Unit 1 and 855 MWe for Unit 2 in the winter but 810 MWe for both units in the summer, when maximum discharge temperature restrictions may limit plant power (1).

The Peach Bottom Atomic Generating Station, owned by Philadelphia Electric Company, is situated in Pennsylvania on the Susquehanna River, approximately 3 miles north of the Maryland border. Peach Bottom Unit 1, a 40 MWe High Temperature Gas Cooled Reactor, was decommissioned in January 1975. It was originally placed in service on May 25, 1967 as a demonstration plant. During its operating lifetime, it generated more than 1 billion kilowatt hours of electrical energy (2). Peach Bottom Units 2 and 3 are both 1065 MWe Boiling Water Reactor systems. Unit 2 began commercial operation in July of 1974, and was followed by Unit 3 in December of the same year (3).

According to their 1978 Ten-Year Plans filed with the Maryland Public Service Commission, none of the State's utilities now plan new nuclear units for at least the next ten years (4). The Douglas Point Nuclear Generating Station planned by the Potomac Electric Power Company has been deferred indefinitely. PEPCO intends to retain the site and to pursue a regulatory determination of the site's suitability.

The Baltimore Gas and Electric Company has deleted from its current ten-year plan the nuclear units scheduled for the Perryman site. On December 1, 1977, the staff of the Nuclear Regulatory Commission issued a report recommending that BG&E's application for an early site review and construction permit be denied on the basis that at least one other site available to the Company was superior overall to the Perryman site, particularly with respect to the safety-related issues of surrounding population density and nearby military activities (5).

The Philadelphia Electric Company does not plan for any new nuclear capacity near Maryland before the 1992-1994 time frame. The prime location is their Fulton site, in Pennsylvania directly across the Susquehanna River from Peach Bottom. Three alternative sites include two properties already owned by the Company at Chesapeake City on the C&D Canal, and Seneca Point on the Northeast River, plus the Bainbridge site, currently sought by the Power Plant Siting Program for its site land-bank. All three of these alternatives are located in Maryland.

Delmarva Power and Light Company currently holds a Limited Work Authorization to begin construction of a nuclear plant at Summit Bridge, Delaware, on the C&D Canal three miles east of the Maryland border. Current plans do not specify the type of reactor to be used and indicate an on-line date beyond their current ten-year planning period.

The Potomac Edison Company is selling its Black Oak site, but retaining its Point of Rocks site, both on the Potomac River. The Point of Rocks site was originally obtained for a nuclear plant with an ultimate capacity of 2500 MWe. However, the Company currently has no plans to use the site.

B. Operations at Calvert Cliffs Nuclear Power Plant

Electrical Power Production

Calvert Cliffs Unit 1 achieved initial criticality on October 7, 1974. Following start-up test procedures, it was placed in commercial service on May 8, 1975. Unit 2 achieved initial criticality on November 30, 1976, and was declared commercial on April 1, 1977. As of January 1, 1978, Unit 1 had produced a total of 14,778,865,000 kilowatt hours of electrical energy, and Unit 2 had produced 4,541,354,000 kilowatt hours (6). This corresponds to an average capacity factor of 75.2% for Unit 1 and 81.4% for Unit 2. The environmental impact calculations made by the Baltimore Gas & Electric Company and by the Atomic Energy Commission for the Calvert Cliffs Plant assumed an 80% capacity factor, and attempted to estimate an annual discharge value that would be representative of the average over the plant's 30 year lifetime (7). In the comparisons of reported vs predicted discharges which follow, the "predicted" values given are based upon 3.42 reactor years of operation at 80% capacity factor. The reader should bear in mind that the plant produced virtually the same amount of the power assumed by the predictions for an equivalent period of time after start-up, but neither reactor has yet built-up its internal inventory of the longer-lived radioactive materials to the levels that will be representative of the average values over the lifetime of the plant.

Radioactive Effluent Releases

Tables IV-1a and IV-1b present listings of the total reported releases from the Calvert Cliffs plant through December 31, 1977, for liquid and atmospheric pathways, respectively (8,9,10,11,12,13,14). Reported releases are derived from measured total releases or from sampling of continuous or semi-continuous low-level discharges. Also included in the tables for comparison are the release values predicted by the Atomic Energy Commission in its Final Environmental Statement before plant start-up, and the values predicted by the Baltimore Gas & Electric Company in 1976 for its "Appendix I Evaluation Report"* (15).

The tabulated quantities of radionuclides released to the environment are small fractions of the releases that are allowable under the portion of the plant's operating license which limits concentrations and quantities of radioactive materials in plant effluents.** The various limitations on plant effluents are summarized in Table IV-2, along with the maximum fraction of the limits actually reached in plant operations through December of 1977.

In addition to the limitations on the quantities and concentrations of radionuclides in effluents, the plant is also required to keep the radiation doses to the public "as low as reasonably achievable". Guideline dose values delineating what the NRC considers reasonably achievable will be discussed later in the impact section of this Chapter. It has been customary for estimates of probable plant radioactivity effluents to be made prior to plant start-up, and to predict maximum dose rates which the power plant could deliver to members of the public, assuming that the plant released effluents at the predicted rate, rather than the maximum allowable rate. Two such sets of effluent predictions have been included in Tables IV-1a and IV-1b. It is useful to assess the accuracy of these predictions as well as trends in the actual release rates in order to assess the level of confidence for prediction of the plant's future performance in keeping doses "as low as reasonably achievable".

In general, the total quantity of radioactive material released to the water has been about one third the level predicted before startup. Total atmospheric releases, which are predominantly Xe-133, have exceeded predictions because the release rate of this radionuclide was underpredicted by more

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* Appendix I to 10CFR50 established "Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion 'As Low As Is Reasonably Achievable' for Radioactive Material in Light-Water-Cooled Power Plant Effluents". All licensed nuclear power plant owners were required to file a report with the NRC by June of 1976, demonstrating that their reactor design complied with the provisions of the Appendix I.

** Effluent concentrations and quantities are limited by Section 2.3 of Appendix B, Environmental Technical Specifications to the Calvert Cliffs Nuclear Power Plant Facility Operating License issued by the U.S. Nuclear Regulatory Commission.

Table IV-1a. Liquid radioactive effluents cumulative to December 31, 1977

Radionuclides	Total Releases Reported by BG&E	AEC Prediction (1973 Est.x 3.42)	BG&E Prediction (1976 Est.x 3.42)
Tritium	1110. Curies	3420. Curies	1160. Curies [(a)]
Dissolved Noble Gases	38.9	-	-
Other	6.14	17.1	2.120
TOTAL	1155.04 Curies	3437.1 Curies	1162.12 Curies
Na-24	0.0356	-	-
Ar-41	0.0000239	-	-
Cr-51	0.320	0.137	0.0000342
Mn-54	0.104	0.205	-
Mn-56	0.000532	-	-
Fe-55	-	0.787	0.0000342
Fe-59	0.371	0.171	-
Co-57	0.00321	-	-
Co-58	1.93	7.18	0.0140
Co-60	0.263	0.205	0.0298
Kr-85m	0.000117	-	-
Kr-87	0.000626	-	-
Kr-88	0.0000726	-	-
Rb-86	-	0.000445	0.00171
Sr-85	0.000729	-	-
Sr-89	0.118	0.00410	-
Sr-90	0.0123	0.000137	-
Sr-91	0.00127	-	-
Y-90	-	0.000185	-
Y-91	-	0.855	0.0000342
Zr/Nb-95	0.406	0.00137	-
Zr-97	0.00391	-	-
Mo-99	0.0156	0.342	0.00157
Tc-99m	-	-	0.00168
Ru-103	0.0789	0.000479	-
Ru-106	0.000639	0.000133	-
Rh-103m	-	0.000479	-
Rh-105	-	0.0000787	-
Ag-110m	0.102	-	-
Cd-109	0.00437	-	-
Sn-113	0.00264	-	-
Sn-125	-	0.00000445	-
Sb-124	0.00518	-	-
Sb-125	0.0103	-	-
Sb-127	-	0.0000257	-
Te-125m	-	0.000410	-
Te-127	-	0.00325	-
Te-127m	-	0.00325	-
Te-129	0.00422	0.342	-

Table IV-1a. Liquid radioactive effluents cumulative to December 31, 1977 (Continued)

Radionuclides	Total Releases Reported by BG&E	AEC Prediction (1973 Est.x 3.42)	BG&E Prediction (1976 Est.x 3.42)
Te-129m	-	0.342	-
Te-131	-	0.000889	-
Te-131m	-	0.00479	-
Te-132	0.000300	0.161	0.000308
I-130	-	-	0.0000684
I-131	0.872	0.923	0.0332
I-132	0.00805	-	0.00103
I-133	0.281	-	0.0195
I-134	0.00201	-	-
I-135	0.0268	-	0.00277
Xe-133	38.0	-	-
Xe-133m	0.242	-	-
Xe-135	0.523	-	-
Cs-134	0.286	3.76	0.718
Cs-136	0.00781	1.27	0.229
Cs-137	0.848	0.205	0.581
Cs-138	0.00658	-	-
Ba-133	0.000172	-	-
Ba-137m	-	0.239	0.445
Ba/La-140	0.233	0.00821	-
Ce-139	0.00206	-	-
Ce-141	-	0.000718	-
Ce-143	-	0.000106	-
Ce-144	-	0.000410	-
Pr-143	-	0.000581	-
Nd-147	-	0.000233	-
Pm-147	-	0.0000445	-
Pm-149	-	0.00171	-
W-187	0.000762	-	-
Au-198	0.000163	-	-
U-235	0.000161	-	-
Np-239	0.0385	-	-
Unidentified	> 0.0295 < 0.136		0.000171 (b)

(a) BG&E also used the 1976 vintage NRC model which would have predicted a release of 1,810 curies of tritium in the 3.42 reactor-years of operation.

(b) This item contains "all other" releases predicted by the BG&E model.

Table IV-1b. Airborne releases cumulative to December 31, 1977

Radionuclides	Total Releases Reported by BG&E	AEC Prediction (1973 Est.x 3.42)	BG&E Prediction[a] (1976 Est.x 3.42)
Total Noble Gases	39400. Curies	12300. Curies	28700. Curies
Total Halogens	.311	0.855	0.79
Particulate Gross β	0.619	-	-
Particulate Gross α	>0.00000181 <0.00000345	- -	- -
Tritium	159.	-	1160.[b]
Na-24	0.000992	-	-
Ar-41	9.20	-	-
Cr-51	0.00674	-	-
Mn-54	0.0494	-	0.000787
Mn-56	0.000330		
Fe-59	-	-	0.000257
Co-57	0.0000249	-	-
Co-58	0.00634	-	0.00257
Co-60	0.0103	0.00116	
Ni-65	0.00000317	-	-
Cu-64	0.0125	-	-
Br-82	0.00107	-	-
Kr-85	7.94	2570.0	6500.
Kr-85m	38.0	-	13.7
Kr-87	11.9	20.5	3.42
Kr-88	21.4	68.4	27.4
Rb-88	1.47	-	-
Sr-89	0.000370	-	0.0000547
Sr-90	0.0000147	-	0.0000103
Sr-91	0.00116	-	-
Zr/Nb-95	0.00774	-	-
Mo-99	0.000271	-	-
Ru-103	0.00135	-	-
Cd-109	0.00000440	-	-
Sn-113	0.000107	-	-
Sn-133	0.00000436	-	-
Te-129	0.0000000805	-	-
Te-132	0.0000389	-	-
I-131	0.313	0.855	0.342
I-132	0.0685	-	-
I-133	0.247	-	0.410
I-134	0.0231	-	-
I-135	0.189	-	-
Xe-131m	23.1	109.	236.
Xe-133	37600.	9400.	21900.
Xe-133m	176.	-	147.
Xe-135	1500.	123.	68.4
Xe-138	1.28	20.5	0.00

Table IV-1b. Airborne releases cumulative to December 31, 1977 (Continued)

Radionuclides	Total Releases Reported by BG&E	AEC Prediction (1973 Est. x 3.42)	BG&E Prediction (1976 Est. x 3.42)
Cs-134	-	-	0.000787
Cs-137	0.00108	-	-
Cs-138	0.9516	-	-
Ba-133	0.00105	-	-
Ba/La-140	0.00564	-	-
Ce-139	0.000498	-	-
Au-198	0.00000634	-	-
Np-239	0.000292	-	-

(a) This model neglects any noble gases contributing less than 3.42 curies to this table and any iodines contributing less than 0.000342 curies to this table.

(b) BG&E also used the 1976 vintage NRC model which would have predicted a release of 1,850 curies of tritium in the 3.42 reactor years of operation.

Table IV-2. Regulatory limitations on radioactivity in Calvert Cliffs effluents

Type of Effluent	Limited Value or Equation	Maximum Fraction of Limit Actually Reached
Total quantity of radionuclides, excluding tritium and dissolved noble gases, in aqueous effluents	10 ci/unit/calendar quarter	0.07
Aqueous concentration for all radionuclides, including tritium and dissolved noble gases	Limits specified in 10 CFR20, Appendix B for concentrations in waters in unrestricted areas	0.000111 (tritium) 0.00393 (dissolved noble gases) 0.0244 (others)
Average quarterly rate of release in atmospheric effluents of all radionuclides except I-131 and particulates with half-lives > 8 days	$\sum_i \frac{(\text{Quantity of nuclide "i"})}{(3.85 \times 10^5)\ (MDC_i)} \leq 0.6$ Where MCD_i values are defined in Appendix B, Table II, Column 1 of 10 CFR20	0.0763
Average annual rate of release in atmospheric effluents of all radionuclides except I-131 and particulates with half-lives > 8 days	$\sum_i \frac{(\text{Quantity of nuclide "i"})}{(3.85 \times 10^5)\ (MDC_i)} \leq 0.08$ Where MCD_i values are defined in Appendix B, Table II, Column 1 of 10 CFR20	0.0732
Quarterly average release rate of I-131 and particulates with half-lives > 8 days	0.16 μ Ci/sec (I-131 equivalent)	0.0538
Annual average release rate of I-131 and particulates with half-lives > 8 days	0.08 μ Ci/sec (I-131 equivalent)	0.0719

than a factor of three.* In order to understand the significance of differences between the predicted and reported release values, it is necessary to make comparisons for individual radionuclides or groups of radionuclides in the context of the various pathways by which they deliver radiation doses to the public.

Atmospheric releases are predominantly radioactive isotopes of the inert or "noble" gases krypton and xenon. These gases do not accumulate in biota or soil, but will give a radiation dose as they blow past an individual. Xenon-133 makes up 95% of the reported airborne releases, and is averaging approximately four times the AEC's predicted release rate. Although relatively large batch releases of Xe-133 during the first half of 1977 resulted in quarterly totals two of three times greater than the average for the remainder of the operating period, it is still clear that the average release rate for the plant will exceed the AEC's predicted value by a factor of three to four. The more recent calculations by BG&E assumed a Xe-133 release rate of 6,000 Ci/yr/unit which has been exceeded by 50% to 70% in operations reported to date. Since Xe-133 has only a 5.27 day half-life, production and discharge of this isotope has already reached equilibrium in the reactors, and an increase is not to be expected with increasing cumulative generation. Since Xe-133 is a gas produced within the fuel road during fission of uranium, it can be expected that the release rate for this isotope will vary somewhat among fuel batches, depending upon the number of imperfections in the fuel cladding. Changes in the leakage rate from the primary coolant loop could also result in future changes in atmospheric release rates for Xe-133.

Except for Xe-135, reported releases of other noble gases have been near or below their predicted values. Kr-89 is the only noble gas radionuclide with a half-life long enough (10.2 years) to allow for continued build-up in the reactor over a period of years. However, reported releases of Kr-85 have been only a few thousandths of the predicted values, and it appears that the turnover of fuel, water and air in the reactors and containments will prevent future increases of the magnitude necessary to approach predicted levels.

Atmospheric releases of radioactive halogens (i.e., iodines and bromines) may be bioaccumulated in the human thyroid gland through several pathways, including inhalation and absorption through the lungs, ingestion of leafy vegetables with radiohalide deposition, and ingestion of milk containing radiohalogens bioaccumulated by cows. Because I-131 has an 8 day half-life and constitutes the majority of radiohalogen releases, it is responsible for the majority of radiohalogen delivered doses.

Releases of radioactive I-131 were approximately one-third of the value originally predicted by the AEC, but closely approximated the values predicted later by BG&E. Releases of the other detected isotopes of iodine were not predicted, except for BG&E's prediction for I-133. Because of their low release rates and very short half-lives, these isotopes are often neglected in impact predictions. Again, because radioactive halogen isotopes all have short half-lives (except for I-129, which has not been predicted or detected), the reactors already should have attained their equilibrium releases rates for this group of radionuclides.

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* As will be discussed later, this release rate is still well below allowable limits, and has not resulted in environmental dose rates of any significance.

Tritium is released from the power plant in the form of water or water vapor (HTO instead of H_2O) and can potentially deliver a radiation dose to the public only by inhalation, absorption through the lungs and subsequent inclusion in body fluids. Atmospheric release of tritium was not predicted by the AEC in their pre-operational calculations. However, more recent NRC dose assessment models predict atmospheric tritium release rates nearly twelve times greater than reported by BG&E for operations to date. BG&E's own recent predictions indicate a release rate more than seven times greater than they have actually reported. Since tritium has a 12.3 year half-life, reported releases might be expected to increase somewhat in the future as concentrations increase in internal plant water systems. Since internal water residence time is more important than either radioactive decay or atmospheric release rate in limiting concentrations, this increase will be less than if the equilibrium concentrations were principally controlled by radiological half-life. Quarterly release data does show a general increase in release rate with time until the last two quarters of 1977, when the rate dropped by two orders of magnitude. BG&E personnel indicate that this decrease in reported releases occurred because of a change in the method of estimating the activity discharged during purges of air in the containment buildings, rather than because of an actual change in the plant's internal concentrations or operating procedures (16). Such variability in discharge estimating procedures is one reason for the large variability in the model predictions, which are based upon earlier observations at other operating reactors.

Original AEC predictions did not include estimates of the isotopic composition for radioactive particulates to be released to the atmosphere. The more recent BG&E predictions do include predictions for 8 isotopes. Actual measurements indicate 29 different radionuclides being released in particulate form, including 6 of the 8 predicted by BG&E. Radioactive particulate releases may potentially enter the human body by deposition in lungs or on leafy vegetables, but these pathways are usually insignificant because of the small quantities of radioactive particulates actually released. Reported release rates approximate BG&E's predictions only for Sr-90 and Cs-137, the other predictions being low by factors ranging from 2.6 to 63. Of the particulate activity actually released, 90% was Rb-88, an isotope not included in the predictions. The presence of this isotope is to be expected, however, since it is produced by the radioactive decay of Kr-88 as well as directly by fission of uranium. Excluding Rb-88, the total of the other particulates released exceed the total BG&E predictions by a factor of 23. Still, the total quantity of particulate releases is quite small, amounting to less than 2 millicuries, exclusive of the Rb-88.

Aqueous releases can roughly be divided into three categories: 1) dissolved noble gases, which do not participate in biological processes, 2) tritium, which does not bioaccumulate, but which does enter biological systems in the same manner as stable hydrogen, and 3) the other elements which chemically interact in both biological and inorganic processes of the environment.

The quantity of radioactive noble gases dissolved in the aqueous releases was not estimated by the AEC in their original predictions for Calvert Cliffs. Since they are chemically inert and the water shields aquatic biota from radiation emitted only a short distance away, dissolved noble gases have insignificant effect in the aquatic ecosystem. Most of the dissolved gas discharge is Xe-133, but the quantity discharged to the water is only about 0.001 of the quantity of Xe-133 discharged directly to the atmosphere.

Aqueous releases to Chesapeake Bay have contained one-third of the AEC's predicted quantities of tritium. The more recent predictions by BG&E indicate that this will be the equilibrium release rate, while the newer NRC model (see footnote to Table 1a) indicates that the release rate will increase with time by nearly a factor of 2. The quarterly total release data are somewhat difficult to extrapolate because Unit 2 has just recently begun operation. However, it does appear that BG&E's predictions are most consistent with the data to present. If so, it indicates that tritium concentrations reach equilibrium between production and discharge within several months of commercial reactor operation, and that both the aqueous and gaseous releases of tritium will remain stable near their present values.

The total of other radionuclides contained in the aqueous discharges has been about one-third the pre-start-up prediction, but is about three time greater than BG&E predicted in its Appendix I Evaluation Report, which considered relatively few isotopes. The radionuclides which have been reported in plant releases and are most likely to be of significance in the Chesapeake Bay ecosystem are Cr-51, Mn-54, Co-58, Co-60, Zr/Nb-95, Ru-103, Ag-110m, I-131, Cg-134, and I-131. Of these, only the two cesium isotopes were predicted in the proper range by the BG&E Appendix I Evaluation Report, while the others were either greatly under-predicted or not included in these predictions at all. The earlier predictions by the AEC more reasonably approximate the reported releases for all these isotopes except Zr/Nb-95, Ru-103 and Ag-110m. Because the ecological portions of the impact prediction models were grossly pessimistic, however, actual measurements of these radionuclides in biota are used later in this Chapter to assess the significance of this under-prediction of releases insofar as it affects actual radiation doses to the public.

Solid Radioactive Waste

Low level radioactive waste shipments from the Calvert Cliffs plant during calendar year 1977 are given in Table IV-3, tabulated by the type of waste and the estimated radionuclide content. There were 19 separate shipments of radioactive wastes by truck from the Calvert Cliffs Nuclear Power plant to Barnwell, S.C. during 1977. Prior to 1977, BG&E was not required to tabulate such shipments and report them to the NRC.

Spent Fuel Accumulation

As of January 1, 1978, Unit 1 had refueled only once and Unit 2 not at all, giving an on-site inventory of 72 spent fuel assemblies in the storage pool. During 1978, both Units 1 and 2 will refuel, bringing the total of spent fuel stored on site to 216 assemblies (17). To date, no spent fuel has been shipped off-site.

In the spring of 1977, President Carter initiated a major change in federal policy by prohibiting the commercial reprocessing or disposal of spent nuclear reactor fuel. Although he announced plans for the federal government to begin acquiring spent fuel from utility companies for federal disposal, the time-table now specified by the Department of Energy does not anticipate that federal acquisition could begin before 1982. Permanent federal disposal sites are not expected to be available before 1988, and perhaps as late as 1993 (18).

Table IV-3. Solid wastes shipped off-site during 1977

Quantity of Wastes

Type of Waste	Volume	Radioactivity
a. spent resin, filter sludge evaporator bottoms, etc.	28.8 m^3	33.9 curies
b. dry compressible wastes, contaminated equipment, etc.	232.0 m^3	0.807 curies
c. irradiated components, control rods, etc.	48.7 m^3	63.6 curies

Composition by Radionuclides

Nuclide	Total Activity
Mn-54	1.75 curies
Co-57	0.102 curies
Co-58	9.94 curies
Co-60	68.3 curies
Zr-95	0.0142 curies
Nb-95	0.0279 curies
I-131	1.74 curies
Cs-134	4.65 curies
Cs-137	10.9 curies
Ba-140	0.267 curies
La-140	0.385 curies

When the Calvert Cliffs plant was designed and constructed, it was assumed that spent fuel assemblies would be stored on-site for cool-down for approximately one year, followed by shipment off-site to a commercial spent fuel reprocessing plant. The spent fuel storage pool was therefore designed to hold 410 fuel assemblies, so that it could accommodate one annual discharge (72 assemblies) from each reactor plus one complete core (217 assemblies), in case it ever became necessary to empty one reactor.

Under the new federal policy, the Calvert Cliffs Nuclear Power Plant would completely fill its spent fuel storage pool in 1980. Unless BG&E makes arrangements to store additional spent fuel on-site, this would force a shutdown of the plant. In response to this situation, BG&E has redesigned the racks which contain the spent fuel in the storage pool (19-23). The new densely-packed racks can accommodate 528 spent fuel assemblies on each of the two sides of the storage pool. On January 4, 1978, the NRC issued amendments to the Facility Operating Licenses for both units at Calvert Cliffs, allowing the new rack design to be placed in both halves of the spent fuel pool. BG&E has since changed the racks in the Unit 2 side, thus providing sufficient storage for continued operation until January of 1982. A similar substitution of racks on the Unit 1 side can be used to extend operations through September 1984, without shipping spent fuel off-site. As of January 1982, 720 assemblies are expected to be in storage. This number could increase to 1000 by 1984 if there is no shipment to a federal facility before that date.

Spent fuel elements are kept at much lower temperatures in the spent fuel pool than they experienced in the reactor core. Experience has shown that even fuel rods which leaked fission products while in the reactor will cease leaking when cooled-down and transferred to the spent fuel pool. In addition, Zircoloy cladding has been demonstrated to withstand storage for many years in demineralized water. Consequently, the storage of additional spent fuel elements is not expected to cause any significant increase in the discharge of radioactivity in effluents from the reactor site.

Safety issues investigated for spent fuel pool rack modifications include the possibility of accidently initiating a fission chain-reaction in the spent fuel pool and the consequences of accidently releasing a puff of radioactive noble gases by damaging fuel rods while they are stored in the pool (e.g., by dropping a heavy object on them). The additional risks involved in utilizing the densely-packed racks at Calvert Cliffs were found to be insignificant in investigations by BG&E (24) and the NRC (25).

C. Radiological Effects Around the Calvert Cliffs Plant Site

Extensive radiological sampling is conducted around the Calvert Cliffs site by both BG&E and the State. In addition, other radiological sampling activities of the State Government elsewhere in Maryland provide context for interpreting the results around Calvert Cliffs.

Sampling methods used to detect atmospheric discharges from the plant in the surrounding environment include:

- Measurement of monthly external radiation dose by thermoluminescence dosimetry (TLD) techniques at multiple sites, to detect radiation doses given by noble gases.

- Collection of iodine and atmospheric particulates by air pump/filter devices at several locations, with gross α, gross β, radiostrontium and γ spectrum analyses of the samples, to detect radionuclides which may give a dose through inhalation.

- Collection of precipitation, local vegetation and soils for γ spectrum analysis to detect deposition of particulate effluents on crops and soils.

- Collection of milk from nearest dairy for radiostrontium and γ spectrum analysis to detect bioaccumulation in cows milk of radionuclides inhaled by cattle or ingested by grazing.

Data reports addressing methodologies and results of these analyses have been published by the various investigators (26-37). Only the overall conclusions will be addressed here.

Detection of power plant effects is complicated by two factors. First, the natural radiation in the environment is not constant. Variations in rainfall and sunspot activity, and disturbances of soils by human activities such as bulldozing and fertilizing all produce variations in the level of natural background radiation. The second complicating factor is fallout from nuclear weapons testing, which continues to deposit some of the same types of radioactive material that are released by the power plant. To date, no measured doses and only one concentration of a radionuclide detected around Calvert Cliffs can reasonably be attributed to airborne releases from the power plant.

Two measurements of atmospheric concentrations of radioiodine by BG&E on-site for the weeks of March 30 to April 6 and April 20 to 27, 1976 are most likely due to plant effluents (29), as radioiodine was not detected at any other location or in precipitation, in milk, or on grass. Inhalation at these measured concentrations, which averaged 0.02 and 0.01 pCi/m^3 for their respective periods, could potentially result in dose rates of 0.0074 and 0.0037 mrem/week, respectively, to an infant's thyroid gland.* NRC regulations set the limit for such doses to 30 mrem/year (0.6 mrem/week average) off-site. Radioactive iodine was again detected in the atmosphere during each of the fallout periods from the Chinese nuclear weapons tests on September 26, 1976, November 17, 1976 and September 17, 1977. Only during fallout from the 1977 test did calculations based on the plant's release rate and meteorological measurements indicate that the plant could have contributed detectable quantities to any of the radioiodine concentrations measured. Plant contributions to measurements could have been as high as 10% of the measured value at an on-site location during the week of September 27 through October 4, 1977 (31), when fallout iodine was detectable at all stations. Two on-site stations also showed detectable concentrations the following week. BG&E's calculations indicate that the plant

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* The thyroid gland of an infant will receive a greater radiation dose than the thyroid gland of an older individual who breaths air with the same concentration of radioactive iodine. Consequently, the infant thyroid gland dose calculation is the controlling parameter for compliance with standards for maximum dose to any organ of an individual in the general public.

may have contributed to these values (31). The equivalent maximum individual thyroid dose due to inhalation of these concentrations was only 0.005 mrem/week. No measurements of radioiodine in milk are attributed to Calvert Cliffs effluents.

Measurable concentrations of radionuclides in atmospheric particulates, precipitation, vegetation and milk have all been attributed to fallout, rather than to the power plant. These conclusions are based upon comparisons of nearfield and farfield data during the periods of fallout.

Measurements of external radiation doses by TLD techniques have resulted in several instances when the BG&E operational phase data exceeded the range expected from their preoperational measurements of ambient doses. Calculations of dose based on the plants release records and meteorological data were used to aid in interpreting these differences. Typically, variations in quarterly doses during the operational phase, which are above the range expected in ambient dose, are on the order of 1 mrem, while calculated plant contributions are on the order of 0.001 mrem or less for the same periods (29,30,31). Since the BG&E control station in Baltimore has also exceeded its expected value by a significant margin, these occurrences have been attributed to the random fluctuations and systematic variations incumbent on any TLD system used to monitor for small increases above natural dose rates.

As previously discussed, release rates of Xe-133 and Xe-135 have been significantly higher than predicted. Calculation of the maximum site boundary dose due to these isotopes for the first quarter of 1977, when the greatest release was reported, produces an estimate of 0.23 mrem total body dose increment and 0.62 mrem skin dose increment (36). These estimates are based on the annual average dispersion factor to a point on the site boundary 1190 m SE of the plant. Calculations using actual meteorological data for that quarter may vary, but the accuracy is sufficient to conclude that the maximum external dose increment due to the plant's operations should be of the same order or smaller than the fluctuations in the TLD monitoring systems used for this work. These calculated dose rates, even if they continued for the entire year, are only about 5% and 6% respectively, of the NRC guidelines applicable to the plant.

For additional perspective, it should be noted that the State's TLD data at Calvert Cliffs and elsewhere have shown over the past two years that the external dose rate near the power plant, including whatever increment is being contributed by the plant, is among the lowest in Maryland (36): about 55 mrem/year compared to a value of 95 mrem/year tabulated by EPA as the Maryland average (41). Moving from the Calvert Cliffs area to the Baltimore area can be expected to increase the annual dose rate by an average of 24 mrem/year. Moving from a wooden frame house to a stone house may add 14 mrem/year. Even the variation of soil composition among sites within the Calvert Cliffs area has been shown to account for differences of 30 mrem/year. Consequently, the dose increments from the Calvert Cliffs airborne releases are not considered significant in the context of normal human activities.

Sampling activities used to address the radiological impact of Calvert Cliffs in the aquatic ecosystem of Chesapeake Bay include sampling water, sediment, and aquatic biota, both edible and forage species.

Discharges of radionuclides to the Bay were predicted to occur only through the cooling water discharge conduit (see Figure IV-1). However, sampling of storm water runoff and the sand below the storm water outfall pipe 002 have revealed that minor amounts of radioactivity are also being discharged by this path (37). At least two discrete incidents (38,39) reported by BG&E to the Maryland Water Resources Administration have been responsible for discharges of radioactive material from this outfall. Continued discharge of barely detectable radioactivity may be due either to continued flushing of contamination caused by these two incidents, or by some other source. Isotopes associated with this discharge include Co-60, Co-58, Mn-54, Cs-134, and Cs-137. Sampling of shorezone fishes, oysters and sediments in close proximity to this outfall has indicated that the radioactivity discharged from the storm drain has probably not made any detectable contribution to radionuclide concentrations in the Bay. This is due in part to the (assumed) small quantity of radionuclides discharged, but also, in large degree, it is due to the rapid dispersion of effluents once they cross the beach and enter Chesapeake Bay. This finding, that some radioactivity may be discharged into stormdrains, should be carefully considered when evaluating other nuclear power plant designs which may be proposed for sites where storm water runoff enters creeks or other natural water bodies with poor natural flushing.

Radionuclides discharged through the cooling water conduit at Calvert Cliffs have been detected in sediments, oysters and crabs (31,32,33,35,37). Although fallout contributions have also been detected, especially in shore zone fishes, the plant's contribution can be ascertained by the near-field/far-field distribution or, in the case of Co-58 and Ag-110m, the additional fact that these isotopes were not detected in recent atmospheric fallout samples.

Table IV-4 presents a list of the maximum concentrations of radionuclides which have been detected in various media and attributed to the power plant's discharges. Of the items listed, it can be seen that Ag-110m has accumulated in the greatest concentrations. This finding was somewhat surprising because discharges of Ag-110m had not been included in the plant's predicted releases nor reported in the plant's effluents prior to the time that the geographic correlation of Ag-110m concentrations in oysters with distance from the plant's cooling water discharge location lead to the conclusion that this radionuclide was coming from the plant. However, Ag-110m had previously been detected in effluents from other nuclear plants, and NRC models current in the summer of 1977 were predicting Ag-110m discharges. The discrepancy between field data and release reports was resolved when it was discovered that an error in BG&E's computerized effluent analysis routine caused AG-110m to be misidentified as Zr-97. Zr-97 (probably actually Ag-110m) was first reported released by the plant in the first quarter of 1976. Ag-110m was first detected in oysters near Calvert Cliffs in the fourth quarter of 1976. By the summer of 1977, the concentration of Ag-110m in oysters near the plant had reached its maximum value to date. While the nearfield concentrations in oysters remained essentially unchanged, Ag-110m reached detectable levels in sediments near the plant and also in oysters near Kenwood Beach, some 6 miles away, by the winter of 1977-78. At this point, it is not yet possible to predict equilibrium concentrations and distributions for the life of the power plant. Ag-110m has a 253 day radiological half-life. Biological turnover in biota and physical movements of water and sediment can be expected to produce a shorter effective half-life for media near the plant's discharge. This may be the case insofar as the Ag-110m concentration in oysters there has remained relatively stable for three quarters, whereas the concentrations could be expected to continue to rise for a period of a few years if radioactive

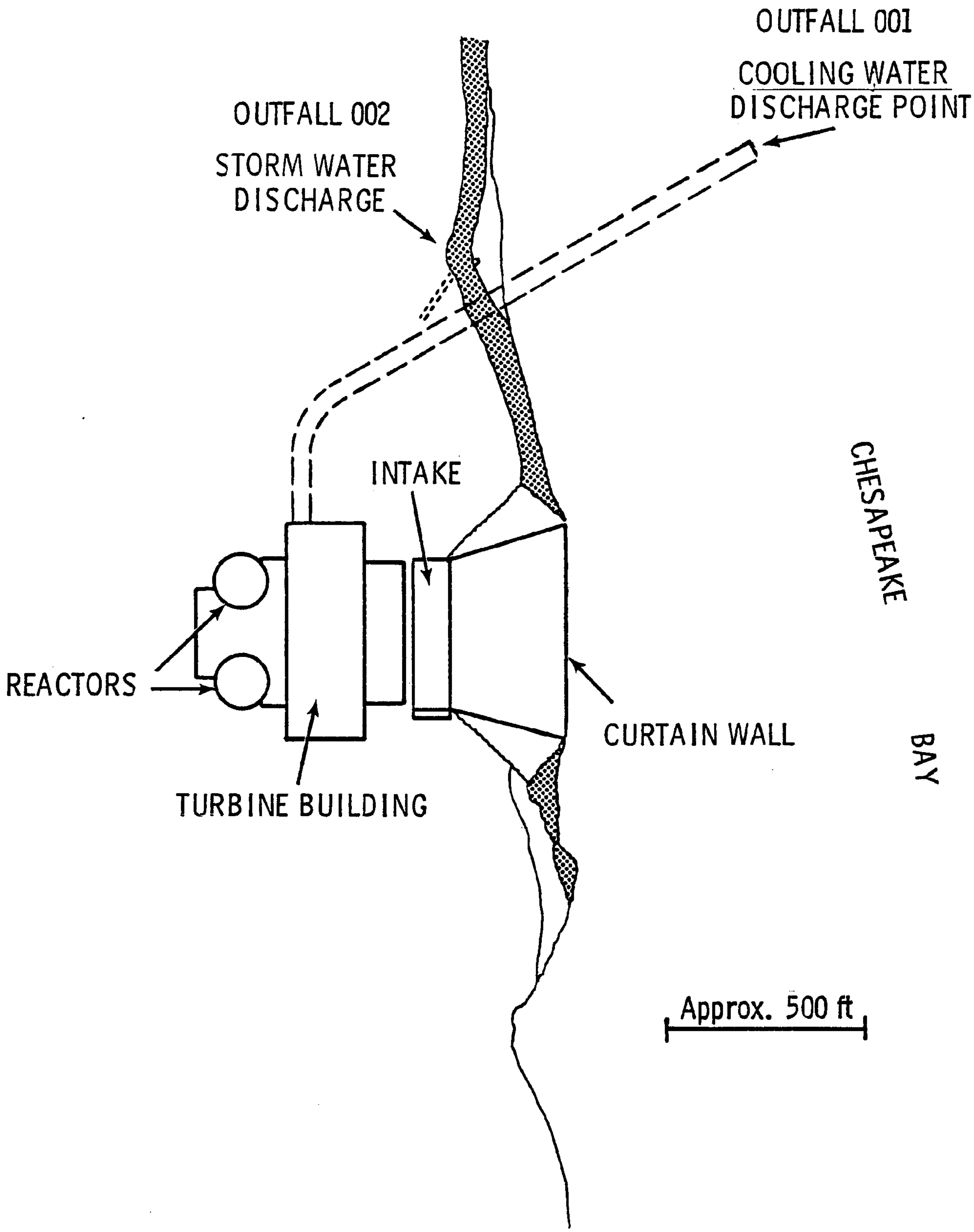

Figure IV-1. Locations of radionuclide discharges into Chesapeake Bay

Table IV-4. Maximum concentrations of radionuclides attributed to plant operation* in various environmental media

Media	Radionuclide Concentration			
	Ag-110m	Co-58	Co-60	Units
Estuarine Biota				
Oysters	620 ± 20	6 ± 5	3 ± 1	pCi/Kg ± 1.96σ (wet)
Crab				
Meat	14 ± 8	--	--	pCi/Kg ± 1.96σ (wet)
Shell	72 ± 7	15 ± 5	--	pCi/Kg ± 1.96σ (dry)
Fishes	--	--	--	
Estuarine Sediments				
Sand	(5 ± 7)	17 ± 5	18 ± 6	pCi/Kg ± 1.96σ (dry)
Clay	31 ± 10	60 ± 7	53 ± 10	pCi/Kg ± 1.96σ (dry)
Beach Sand				
Discharge 002 Area	--	12 ± 4	53 ± 4	pCi/Kg ± 1.96σ (dry)
Other Areas	--	--	--	pCi/Kg ± 1.96σ (dry)

* The radionuclides Zr-95, Nb-95, Ru-102, Ru-106 have also been detected in these media. Although documented as constituents of plant releases they are also fallout products. Levels in the plant area are not significantly different from control area concentrations, thus any plant contribution to the existing fallout-contributed level is unassessable. Such possible contributions have been neglected here as insignificant contributers to total impact.

decay were the only operable removal mechanism. However, variations in the plant's discharge rate and seasonal fluctuations make such treatments of the data very speculative at this time. A program has been started in which uncontaminated oyster stock is placed directly in the Calvert Cliffs effluent for various periods of time to provide a properly controlled experiment for the evaluation of these various effects.

Figure IV-2a and IV-2b demonstrate that Ag-110m has become the predominant radioisotope in oysters near the power plant discharge. However, the dose received by an individual eating these oysters is quite small. An adult would receive a dose of 0.000009 mrem to the whole body and 0.006 mrem to the gastrointestinal tract by eating one dozen "select" (large) oysters with a Ag-110m concentration of 500 pCi/Kg.*

When computing doses to the "maximum exposed individual", the NRC's Regulatory Guide 1.109 (40) recommends an assumption, in lieu of more specific data, that an adult will eat 5 kg of seafood other than fish, each year. Five kilograms of oysters corresponds to about 24 dozen "select" or 29 dozen "standard" oysters. Five kilograms of crab meat corresponds to about 15 dozen medium crabs. Rather than arbitrarily divide the assumed 5 kg intake between crabs and oysters, Table IV-5 gives the doses that individuals of various ages would receive if they ate 5 kg of oysters and 5 kg of crab meat that contained the radionuclide concentrations given in Table IV-4 as the maximum contributions yet detected from the power plant. None of these doses is considered significant in comparison with the fluctuations created in an individual's natural dose rate by routine human activities, as was discussed in the section on impacts of the airborne effluents.

For purposes of absolute risk evaluation, it has been customary to assume that any incremental radiation dose, no matter how small, increases the risk of certain biological disorders, including cancers, thyroid nodules and genetic defects in progeny. Table IV-6 gives the assumed incremental risk of each effect due to 1 mrem of dose to the appropriate organ (41). In this context, an individual who lived for a year at the site boundary where the maximum dose rate occurs and who ate 5 kg of oysters and 5 kg of crabs from the plant discharge area would expose himself to an additional risk of about one in three million that the nuclear power plant's effluents would induce a biological disorder in him, and an additional risk of about one in five hundred million that it would cause a serious genetic effect in his progeny. Such additional risk levels are miniscule compared to the normal risk levels (43) associated with the same effects in the U.S. population today.

D. Conclusions

Although the Calvert Cliffs Nuclear Power Plant is reporting releases to the atmosphere which are several times greater than originally predicted, and although the reported aqueous releases of the more important radionuclides are greater than BG&E predicted when demonstrating compliance with NRC's design bases dose values, it is still concluded that operations of the plant to date have resulted

* The value of 500 pCi/kg is used for illustration because it is a reasonable approximation of the concentrations in oysters in the plant vicinity, where values ranged from 620 pCi/kg directly in the discharge plume, to 420 pCi/kg at Camp Canoy.

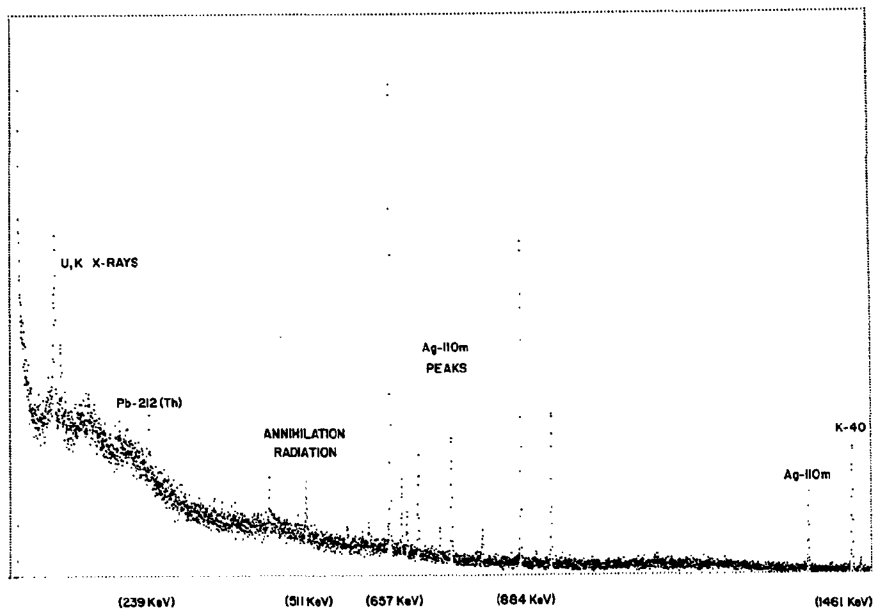

Figure IV-2. (A) Gamma spectron of oysters from Calvert Cliffs Nuclear Power Plant discharge area showing effluent radionuclide bioaccumulation

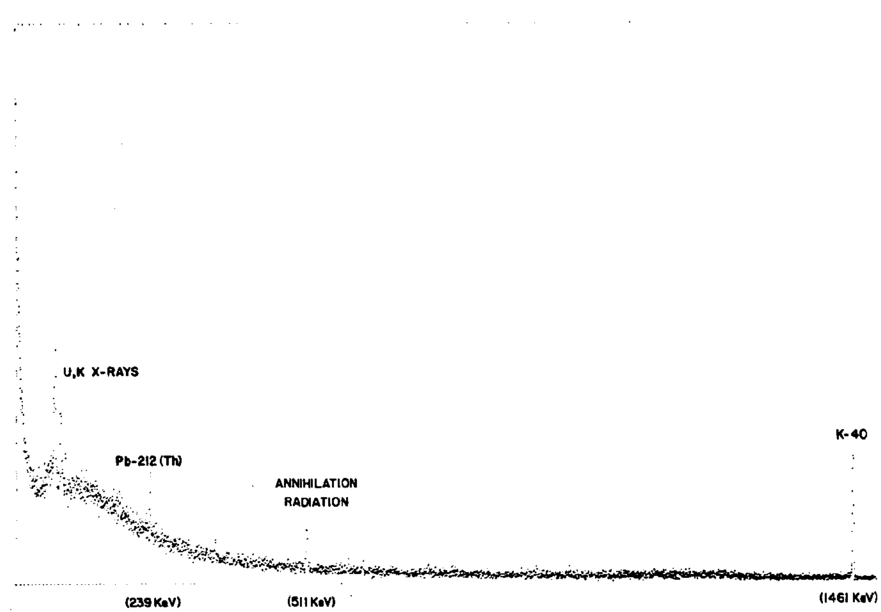

Figure IV-2. (B) Gamma spectrum of oysters from Kenwood Beach area showing only natural radioactivity

Table IV-5. Dose commitment[a] due to Calvert Cliffs Nuclear Power Plant effluents for an individual who takes all his seafood from the plant vicinity (assumes radionuclide concentrations given in Table IV-4).

Age Group	Adult	Teen	Child
Consumption:			
Oysters	5.0 Kg/yr (29 dozen)	3.8 Kg/yr (22 dozen)	1.7 Kg/yr (10 dozen)
Crabs	5.0 Kg/yr (15 dozen)	3.8 Kg/yr (11 dozen)	1.7 Kg/yr (5 dozen)
Total Body Dose:			
Co-58	0.0000543 mrem/yr	0.0000553 mrem/yr	0.0000609 mrem/yr
Co-60	0.0000708	0.0000722	0.0000796
Ag-110m	0.000279	0.000284	0.000314
Total	0.00040	0.00041	0.00045
Bone Dose:			
Co-58	(b)	(b)	(b)
Co-60	(b)	(b)	(b)
Ag-110m	0.000507	0.000494	0.000581
Total	0.00051	0.00049	0.00058
Liver Dose:			
Co-58	0.0000242	0.0000240	0.0000119
Co-60	0.0000321	0.0000320	0.0000270
Ag-110m	0.000469	0.000467	0.000392
Total	0.00053	0.00052	0.00043
Kidney Dose:			
Co-58	(b)	(b)	(b)
Co-60	(b)	(b)	(b)
Ag-110m	0.000922	0.000891	0.000731
Total	0.00092	0.00089	0.00073
GI Tract Dose:			
Co-58	0.000491	0.000331	0.000116
Co-60	0.000603	0.000417	0.000149
Ag-110m	0.191	0.131	0.0467
Total	0.19	0.13	0.047

(a) The dose commitment from ingestion of a given quantity of a radionuclide is the total dose that will be received by the individual before the radioactive material is lost from the body by excretion and/or radioactive decay.

(b) Dose/concentration conversion factors not available.

Table IV-6. Dose-risk conversion factors

Incremental probability of a particular health effect caused by radiation dose:

- 1 chance in 5,000,000 per mrem total body does for fatal cancer.
- 1 chance in 5,000,000 per mrem total body does for non-fatal cancer.
- 1 chance in 250,000,000[(a)] per mrem gonadal dose for serious genetic effect in progeny
- 1 chance in 17,000,000 per mrem thyroid dose for thyroid cancer[(b)]
- 1 chance in 4,000,000 per mrem thyroid dose for benign thyroid nodule[(c)]
- 1 chance in 25,000,000 per mrem lung dose for fatal lung cancer

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(a) Gonadal dose risk is established on the basis of a continuous annual exposure rate for a 50 year generation time. The value given here is based upon 1/50 of the estimated value for the continuous 50 year exposure. That value is 200 effects/yr for 10^6 person-rem annual exposure in the U.S. population with a 50 year generation time.

(b) Usually not fatal.

(c) The absolute risk level for benign thyroid nodule incidence was not given in reference 41, but is computed here as the risk of thyroid cancer given by reference 41 times the ratio of benign-to-cancerous radiogenically-induced thyroid growths given in Reference 42.

in doses to maximally exposed individuals which are well within the guidelines established by the NRC. These guidelines are given in Table IV-7, along with estimates of the fraction of the guidelines values which the plant has actually contributed.

Predictions regarding future release rates and environmental concentrations of radionuclides produced by Calvert Cliffs are difficult to make with accuracy, given the present state of predictive models and the short period of actual plant operations available for model tuning. However, in view of the very small fractions of the "as low as reasonably achievable" dose guideline values now resulting from plant operations, and with the absence of any visible trends of increasing radionuclide release rates, it appears that the Calvert Cliffs Nuclear Power Plant should continue to operate well within applicable standards.

Table IV-7. Comparison of Calvert Cliffs radiological impact estimates with NRC guideline dose value

Type of Dose	Appendix I[a] Design Objectives	Fraction Given by Calvert Cliffs (2 Units)	Point of Dose Evaluation
Liquid Effluents			
Dose to whole body from all pathways	3 mrem/yr per unit	(0.007%)	Location of the highest dose offsite.[b]
Dose to any organ from all pathways	10 mrem/yr per unit	(0.46%)	Same as above.
Gaseous Effluents[c]			
Gamma dose in air	10 mrad/yr per unit	(2.5%)	Location of the highest dose offsite.[d]
Beta dose in air	20 mrad/yr per unit	(3.4%)	Same as above.
Dose to whole body of an individual	5 mrem/yr per unit	(<5%)	Location of the highest dose offsite.[b]
Dose to skin of an individual	15 mrem/yr per unit	(<4.8%)	Same as above.
Radioiodines and Particulates[e] Released to the Atmosphere			
Dose to any organ from all pathways	15 mrem/yr per unit	(<0.8%)	Location of the highest dose offsite.[f]

(a) Evaluated for a maximum exposed individual.

(b) Evaluated at a location that is anticipated to be occupied during plant lifetime or evaluated with respect to such potential land and water usage and food pathways as could actually exist during the term of plant operation.

(c) Calculated only for noble gases.

(d) Evaluated at a location that could be occupied during the term of plant operation.

(e) Doses due to carbon 14 and tritium intake from terrestrial food chains are included in this category.

(f) Evaluated at a location where an exposure pathway and dose receptor actually exist at the time of licensing. However, if the applicant determines design objectives with respect to radioactive iodine on the basis of existing conditions and if potential changes in land and water usage and food pathways could result in exposures in excess of the guideline values given above, the applicant should provide reasonable assurance that a monitoring and surveillance program will be performed to determine: (1) the quantities of radioactive iodine actually released to the atmosphere and deposited relative to those estimated in the determination of design objectives; (2) whether changes in land and water usage and food pathways which would result in individual exposures greater than originally estimated have occurred; and (3) the content of radioactive iodine in foods involved in the changes, if they occur.

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41. "Radiological Quality of the Environment in the United States, 1977", Office of Radiation Programs, U.S. Environmental Protection Agency, Washington, D.C. EPA 50/1-77-009, September 1977.

42. "Radiation-Associated Thyroid Carcinoma", edited by L.J. Degroot, Grune & Stratton Inc., New York, 1977.

43. Power Plant Cumulative Environmental Impact Report. Maryland Power Plant Siting Program PPSP-CEIR-1, September 1975.

CHAPTER V

SOCIO-ECONOMIC IMPACT

The construction and operation of an electric generating station may have significant economic and social impact upon the community where it is located. Among the many possible effects usually considered are changes in:

- population, housing and school enrollment
- transportation and congestion
- income, employment, and business activity
- local government spending and tax revenues.

For convenience, these effects are usually divided into changes affecting the social and economic functions of the private sector and changes affecting tax revenues or the demand for services in the public sector.

The socio-economic effects of power plant construction stem from the rapid increase in population resulting from a sudden increase in the local work force during plant construction. Both workers who relocate within the area and commuters can potentially exceed the capacity of the public and private services, facilities, markets, and institutions -- the local social and economic infrastructure -- which serve a given community, county, or region. The scale of socio-economic effects from construction depends on the nature of the region where construction occurs, as well as on the relative proportions of commuters, residents and relocating workers employed on the project.

There is a paucity of actual monitoring data or before and after comparison studies for the socio-economic effects of power plant development. In Maryland, the Power Plant Siting Program has studied the effects of construction of the Calvert Cliffs nuclear power station (1).* More recently, the program has developed a model for estimating the socio-economic effects of power plant development (2), and has used the model to estimate these effects for four Eastern Shore counties (3).

A. Employment

The driving force for socio-economic effects is the large labor force necessary for the construction of a modern power plant. It has been estimated that at the peak of construction activity, some 3,200 workers would be involved in the construction of a two-unit, 2,400-MW nuclear power plant, and 800 for a two-unit, 1,200-MW coal-fired plant (3). While construction

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* The Calvert Cliffs study is strictly an ex post study. It does not provide baseline data, and does not attempt to separate out the effects caused by other simultaneous local or national developments.

goes on, these workers purchase goods and services from the local retail economy, increasing local business retail activity. This, in turn, leads to increased wholesale business activity. The result is an increase in local income and employment, which leads to further increases in local business activity, employment and income. It is the sum of these employment gains -- direct construction labor plus the additional employment induced by the increase in local business activity -- which is the principle driving force for the local effects brought on by power plant construction.

Figure V-1 shows the number of workers involved in the construction of a 2,400 MW nuclear or 1,200 MW coal-fired power plant over the life of the construction project, assuming a nine year construction schedule*. The employment profiles include both workers directly involved in construction and workers employed by firms which supply materials and services to the construction project.

The profiles in Figure V-1 show two important characteristics. First, employment is not uniform over the construction period. As a result, the effects tend to be at their greatest during the middle years of construction, and generally diminish by the time the power plant enters service. Second, for these examples peak construction employment for a fossil-fueled plant is much lower than for a nuclear plant -- only 25% for the plant sizes shown here. In addition, employment for a fossil fuel plant is relatively uniform for a period of several years, and does not show the sharp employment peak characteristic of the nuclear case. As a result, the socio-economic effects which result from fossil fuel construction tend to be much less than those from nuclear plant construction, and are more uniform over time.

The scale of the effects that these employment changes have on local social and economic conditions depends primarily on the ability of the local region or county to provide workers from its own population, and on the ability to absorb the new workers who decide to move in during the construction period. Both the ability to provide workers and to absorb a rapidly increased population are a function of the existing population base and the size and integration of the local economy. A large, urbanized county would experience little negative socio-economic impact from a large construction project because the labor force available from its large population reduces significantly the number of workers who must be hired from outside of the county, and its large population and substantial wholesale and retail business sector are able to absorb the new workers who do move into the county and meet the demand for goods and services which they create. By contrast, the small work force, population, and economy typical of many of Maryland's smaller rural counties are less able to absorb the changes that accompany a large construction project.

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* This construction schedule was selected even though it is likely to represent a more rapid construction timetable than a utility of the size assumed in the Eastern Shore study (3) is likely to consider. The purpose of the rapid construction assumption was to provide estimates which would be unlikely to under-state the amount of stress which the affected communities would experience.

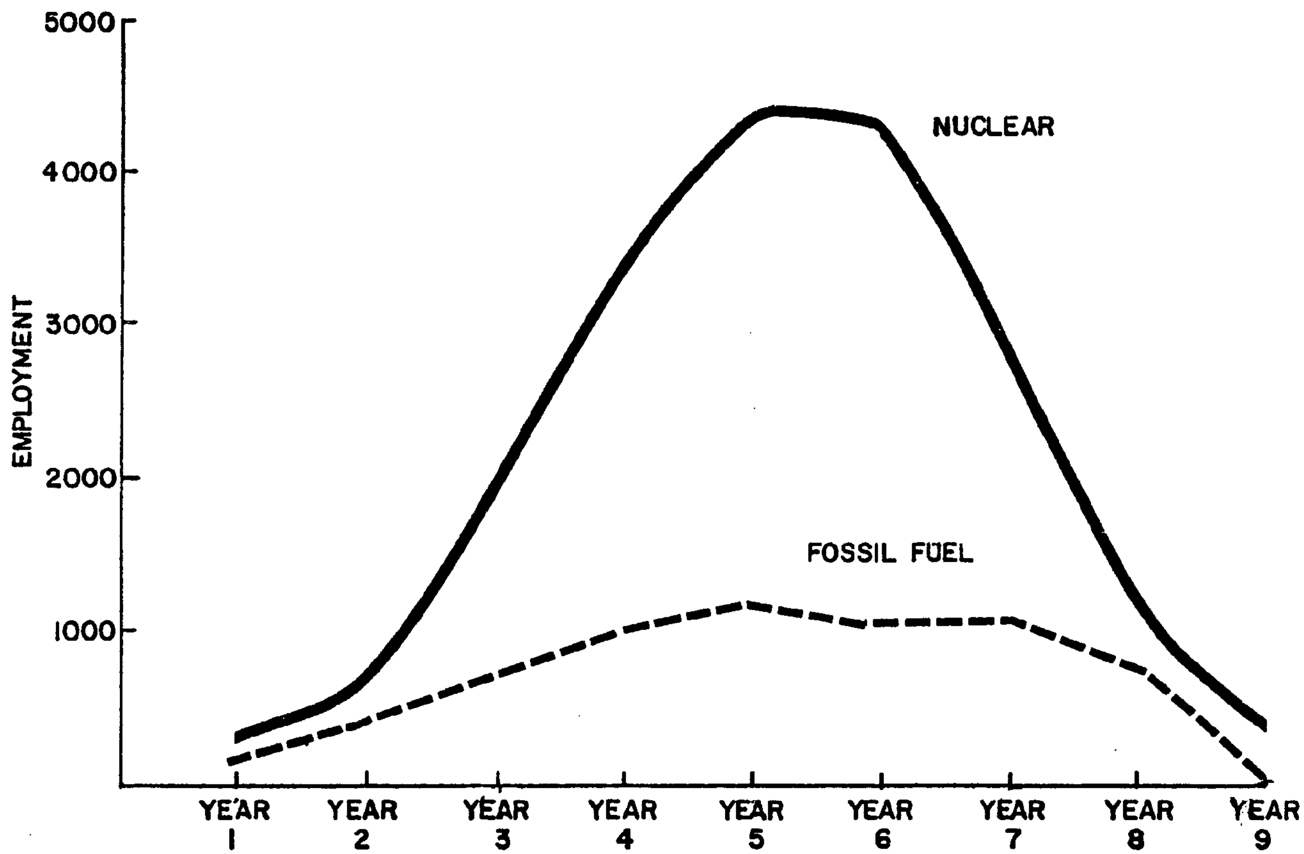

Figure V-1. Total employment profiles for electric power plant construction

Most of the rural counties of the State are located within a relatively short distance (measured in driving time) from the more populous counties and larger metropolitan areas. As a result, even in these rural counties, many of the more severe socio-economic effects which may result from large construction projects are mitigated by their relative proximity to larger labor force concentrations and urban centers. The disruption found in some Western coal and energy development areas where virtually the entire work force was forced to migrate to the construction site is not likely to occur in Maryland. While such large-scale changes are not likely to occur, some migration effects are possible for some of the rural counties.

In a rural or semi-rural area, much of the skilled labor force required for power plant construction comes from outside the local economy, although some local workers have appropriate skills and are able to obtain construction jobs on the plant. Most of the local workers who obtain construction jobs are semi-skilled and unskilled workers (3). Since construction jobs for all classes of workers traditionally have high wage levels, these jobs provide an opportunity for local workers to significantly increase their income. In Calvert County, farm laborers were able to triple their earnings by working on the construction of the Calvert Cliffs plant, where the lowest construction wage was $6.50 per hour (1). As a consequence of these higher wages, some local firms and farms found it difficult to find workers or found workers available only at higher wages than were traditionally paid. In the extreme, some firms dependent on low-wage labor were reportedly forced out of business (1).

The total effect of power plant construction on the local labor market results from both the demand for workers at the plant site, and the increase in the number of new jobs created by the increased demand for goods and services. Table V-1 shows the predicted size of this impact for the case of the construction of a nuclear plant in four Eastern Shore counties (3). Line 5 shows the estimated increase in the number of additional local workers hired from the current population in the peak year, which is shown as the percentage of current resident employment in Line 6. Line 7 shows the total number of additional workers residing in the county (current residents plus workers who move to the county as a result of the new job opportunities), shown as a percentage of current resident employment in Line 8.

The effects caused by construction period employment changes are more complex than the numbers shown in Table V-1 would appear to indicate. As can be seen from the data in the table, there is a great deal of variation in the employment effects that can be expected from the construction of a power plant in different counties within the same relatively small region. The size of the total change in county employment is influenced by the amount of induced employment which occurs within the county itself. The closer the plant site is to a major metropolitan area, the larger will be the number of these induced jobs which will occur in other counties, as can be seen in the differences in in-migration between Kent and Dorchester Counties. The reduction in the local share of these induced jobs is largely due to the reduction in the proportion of workers who find it desirable to eliminate commuting time by moving into the project county, and to the convenience with which both contractors and workers can purchase goods and services outside the project area.

Table V-1. Employment effects -- Four Eastern Shore Counties

	Kent County	Queen Annes County	Dorchester County	Wicomico County
Baseline County Employment, Total	6,845	7,085	13,960	23,395
Increase in County Employment, Total, Peak Year	4,905	4,770	4,895	5,616
Increase in County Employment, Total, Peak Year, %	71.7%	67.3%	35.1%	24.0%
Baseline County Employment, Current Residents	6,368	7,378	12,160	22,647
Increase in County Employment, Current Residents, Peak Year	1,115	999	1,105	1,882
Increase in County Employment, Current Residents, %	17.5%	13.5%	9.1%	8.3%
Increase in County Employment, Current Residents and In-migrants, Peak Year	1,937	1,671	2,188	3,092
Increase in County Employment, Current Residents and In-migrants, Peak Year	30.4%	22.6%	18.0%	24.0%

Similarly, the data in Table V-1 reflect the fact that the further the project is from a metropolitan area, the larger the number of workers who elect to move into the project area, and the larger the proportion of local workers likely to be hired for the project. While the number of workers moving into the area is the major source of population effects, it is the number of local workers hired for the project that results in local employment effects. In the three counties closest to metropolitan areas, the number of local workers hired as a direct or indirect result of construction is lowest. However, the base work force in two of these counties (Kent and Queen Annes) is small enough that this change represents a significant shift in the local labor market, and is likely to have significant effects. By contrast, the largest numerical change in the local labor force in Table V-1 occurs in the largest of the four counties, Wicomico, where the relatively large and growing labor force is likely to be able to provide the additional workers over the five year period leading up to the peak with little noticeable change in local labor market conditions.

B. Population

Table V-2 shows the predicted increase in county and nearby municipal populations at the peak construction year for each of the four Eastern Shore counties (3). The largest population increases occur in the counties which are furthest from the population centers of Baltimore, Washington, and Wilmington.

The effect of this population change is determined less by the absolute size of the increase than by the size of that increase relative to the existing local population. Localities with larger population bases tend to possess more developed infrastructures. An influx of new residents into these larger communities is less likely to affect existing social patterns because the size of the population change is relatively small and therefore more readily absorbable, and because the more developed infrastructure is less likely to be subject to increased crowding and inconvenience that can lead to increased social stress.

The effect of the population changes predicted in the Eastern Shore study (see Table V-2) was estimated to be greater in Kent and Queen Annes Counties, whose major communities (Chestertown and Centreville, respectively) are relatively small. By contrast, the larger population base of Wicomico County would experience only slight effects over the same five-year period.

The estimates of the effects of the population changes shown in Table V-2 demonstrate the complex relationship between in-migration, base population, distance from metropolitan areas, and socioeconomic effects. The counties closest to major metropolitan areas (Kent and Queen Annes Counties) were estimated to receive the smallest amount of in-migration, due to the relative east of commuting. But as a result of the small population base of those counties and their major communities, the effects of the projected population changes is likely to be largest. By contrast, the counties with the largest amount of in-migration (with as much as 80 percent more in-migration) were also the counties with the largest population base, and were projected to experience the smallest adverse effects from the construction-period population changes.

Table V-2. Population effects -- Four Eastern Shore Counties

	Kent County	Queen Annes County	Dorchester County	Wicomico County
Increase in County Population	2,034	1,743	2,740	3,132
Increase in County Population, %	13%	10%	9%	5%
	<u>Chestertown</u>	<u>Centreville</u>	<u>Cambridge</u>	<u>Salisbury</u>
Increase in Municipal Population	637	279	1,477	780
Increase in Municipal Population, %	18%	15%	13%	5%

Source: Reference (3)

C. Housing

One potential impact of the population increase that is likely to accompany power plant development in rural counties is the effect on the housing market. The influx of new residents into these counties results in a rapid increase in the demand for both conventional and temporary housing. In many of the more rural counties in the state, the housing industry has experienced a protracted period of slow growth. Without adequate planning, the housing industry may find itself unprepared to respond to such a rapid increase in the demand for new units. As a result, most of the housing units purchased or rented in these counties are likely to be existing units or temporary units.

Given the relatively high wage scale, power plant workers moving into a county are typically willing and able to pay higher prices than other residents for all available homes and rental units. In the case of Calvert Cliffs, rental prices increased to two and three times their former levels (1).* Farmers and landlords experienced windfall income during a period in which a tight market permitted the rental of even marginal properties. The higher rents also resulted in the displacement of former low and moderate income families unable to increase their housing expenditures. Instances were reported of public employees, especially teachers, having been forced to seek housing outside the County (1).

The predicted effects on housing markets of construction of a power plant on the Eastern Shore (3) varied considerably according to the size and nature of the county in which a plant might be located (Table V-3). However, given the present low population growth rates of the region, the housing markets in all four counties are likely to be strained during peak years of construction for a plant of the size considered. Significant shortages of both permanent and temporary housing units are likely during the two peak years of the nuclear plant construction activity; in one county (which is already experiencing a tight housing market) the shortage was estimated to last for a four year interval.

A shortage of temporary housing units during the construction period may be fairly easily mitigated through adequate planning, once the scale of the housing deficit is known. Mitigating the shortage of permanent units is more difficult and will require greater planning on the part of the appropriate unit of local government, the utility, and contractor.

It has been suggested that the increased demand for housing and higher housing prices of the construction period provide an opportunity, with adequate planning, to upgrade the existing housing stock, particularly substantial units (4). Some counties may require both technical and financial assistance in order to properly plan and carry out an effective mitigation or upgrading program.

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* As noted earlier, the Calvert Cliffs study does not permit separation of Calvert Cliffs impacts from the effects of other simultaneous developments.

Table V-3. Housing effects -- Four Eastern Shore Counties

Year	Kent County		Queen Annes County		Dorchester County		Wicomico County	
	Conventional	Mobile Home	Conventional	Mobile Home	Conventional	Mobile Home	Conventional	Mobile Home
1	no deficit	no deficit	no deficit	no deficit	no deficit	no deficit	no deficit	no deficit
2	no deficit	no deficit	no deficit	no deficit	no deficit	no deficit	no deficit	no deficit
3	no deficit	no deficit	no deficit	no deficit	- 16	- 2	no deficit	no deficit
4	- 72	- 70	no deficit	- 63	-168	- 69	no deficit	-111
5	-166	-144	- 79	-143	-276	-198	- 67	-349
6	-177	-130	- 88	-131	-299	-215	-149	-301
7	- 62	- 55	no deficit	- 66	-153	- 93	- 16	-124
8	no deficit	no deficit	no deficit	no deficit	no deficit	- 4	no deficit	no deficit
9	no deficit	no deficit	no deficit	no deficit	no deficit	no deficit	no deficit	no deficit

D. Transportation

The increase number of resident and commuting workers during the construction frequently produce significant traffic congestion difficulties (1). The impact on traffic congestion is a function of the increase in the number of commuters and the available carrying capacity of the relevant transportation routes, dictated by local conditions. In the case of Calvert Cliffs, a traffic increase of an estimated 1,200 vehicles was experienced during the morning shift. That increase represented 150% of the hourly capacity per lane of the major two-lane road used to reach the plant, resulting in significant rush hour congestion.

The study of four Eastern Shore counties estimated that the increase in the number of commuters coming into the county ranged from a low of 103% (2,524) to 664% (3,101). The county receiving the largest increase (relative and absolute) in the number of commuters was the least likely to experience significant traffic congestion because of the capacity of the major roads leading to the area (3). For each of the other three counties, significant traffic congestion was anticipated at particular points. Those congestion points all occurred at two-lane bridges crossing rivers in the area. In each case, the congestion point had been previously identified by the Maryland Department of Transportation in its long-range plan.

Because the severity of traffic congestion is likely to be dictated by local conditions, it is not possible to reach a general conclusion about the extent to which traffic congestion during plant construction can be mitigated. With adequate advance planning, severe congestion problems that result from existing bottlenecks can be eliminated by altering highway improvement schedules. Congestion resulting from construction period overcrowding of otherwise adequate roads and bridges may be reduced by adjusting work schedules and traffic flow patterns. The extent to which appropriate mitigation measures will succeed in reducing traffic congestion depends on the ability to make long-range planning decisions for road improvements and congestion scheduling.

E. Business Activity

As indicated above, power plant construction may bring a large infusion of new money into a community. Power plant construction spending on payrolls and the purchase of materials represents a major source of potential income for local residents and businesses, particularly in more rural counties. Since the majority of construction material and many of the workers come from outside the local area, large amounts of this spending may leave the area unaffected. However, the amount of local spending that does occur may still constitute a major increase in personal income and in local business activity.

Table V-4 presents predicted estimates of the change in county business activity from the Eastern Shore study (3). The data from the table indicate that in all cases the impact of power plant construction activity on smaller counties can be substantial, in spite of the relatively small proportion of total spending that occurs within the local county. In counties containing larger communities with larger, more diversified economies (which also results in the attraction of more resident workers), a greater proportion of total spending can be retained within the local economy, although that increase represents

Table V-4. Effects on local business -- Four Eastern Shore Counties

	Kent County	Queen Annes County	Dorchester County	Wicomico County
Increases Service Receipts, Peak Year	3,630,000	2,787,000	2,732,000	7,542,000
Increased Service Receipt, Peak Year, % Increase	89%	108%	47%	35%
Increased Wholesale and Retail Sales, Peak Year	35,538,000	29,993,000	35,574,000	50,336,000
Increased Wholesale and Retail Sales, Peak Year, % Increase	61%	51%	41%	14%

a smaller proportionate increase in the county's business volume. (See, for example, Column 4 of Table V-4).

Those county-to-county variations also point to another difference: the smaller counties without large communities typically have a local business structure whose firms are small in size, established, and are frequently not able to respond quickly to a large, rapid change in the size and nature of their market. As a result, these firms are unable to capture as large a share of the new business potential as they might otherwise. Such firms are more likely to be adversely affected by competition by new firms entering the area to capture a share of the plant-induced business activity.

Adequate planning by the existing local business community can increase the amount of business volume and income obtained by the local economy during the construction period.

F. Fiscal Effects

The increase in the number of workers during the construction phase will result in an increase in the demand for public services provided by local and county governments. This increase stems in part from the variety of public services -- such as police and fire service -- required by the total increase in work force, including commuters. Most of this increase comes from those workers who move into the county and make use of schools, fire and police protection, water and sewage treatment, social services and general public administrative functions.

In response to this increased demand, local government has several options available. Public officials may choose to maintain public services at the existing per capita level, which would require increasing the local government budget in proportion to the population increase. Alternatively, recognizing the short-term nature of the increase, public officials may permit the per capita level of services to decline by not expanding services in proportion to the population change. At the limit, services may not be expanded at all.

With the exception of plant sites in the sparsely populated western states, local governments have generally not experienced massive increases in public budgets or major overcrowding of services due to power plant construction. This experience has usually been explained by the fact that power plant construction, particularly in Eastern states like Maryland, has generally taken place in counties located close enough to metropolitan areas to have relatively well developed infrastructures. As a result of the proximity to metropolitan areas, the proportion of workers moving into a project area is also relatively small (see Tables V-1 and V-2). Because the population increases and increased service requirements that do occur are likely to be relatively small and of short-term in duration (see Figure V-1), local officials have frequently found it unnecessary to greatly expand services and budgets (1,4).

The experience in Calvert County during the construction of the Calvert Cliffs plant is similar to that of other Eastern states. County officials elected to avoid major increases in the county budget during the construction period (1). Some sections of county government did experience increased service requirements. For example, housing shortages, some portion of which stemmed from the Calvert Cliffs construction, resulted in increased use of housing services. Administrative services such as zoning and building permit issuance also increased. School officials estimated an increase of 250 in school enrollment as a result of the work force, an increase of about 3.8 percent. However, the county was able to meet these and other service requirements without a significant budget increase.

Balanced against this demand for services is an increase in revenues. Before the plant comes on line, increased housing prices, new construction of houses, increased local income, and business activity will all increase tax revenues. After the plant begins to operate, the county receives tax income from the property and capital taxes of the plant.

The crucial question for local government is the extent to which these revenues will match the increased government service costs. In the absence of accurate revenue projections, local government officials may be reluctant to expand services and risk deficits.

Pointing to increases in the demand for services which occurs during the construction phase but which diminish at the end of construction and to the increased tax revenues that accrue significantly to the county only after the plant begins operating, local planners have commented on the mismatch in the timing of their expenditure and revenue changes. The size of the potential mismatch can be seen in estimates calculated for Maryland's Eastern Shore (3). Table V-5 shows the annual deficits each of the four counties would experience under the assumption that they increased their service expenditures in proportion to their anticipated population increases (3). Table V-6 show the maximum deficit of each jurisdiction as a percentage of total local revenues in the appropriate year (3).

The data in Table V-5 illustrates the variation that exists between counties. These variations are the result of differences in the various tax rates and in the extent to which workers move into the county and provide increased tax revenues through increased property values and property taxes and increased sales taxes and business taxes. Dorchester and Wicomico Counties, which experience the largest absolute increase in population, and which also have more extensively developed infrastructures, experience a balanced flow of revenues and expenditures. The other counties and all of the cities -- which experience much of the population impacts but less of the revenue benefits because of plant location -- all experience deficits throughout the construction phase.

As seen in Table V-5 and V-6, the county deficits are significant, but are manageable in size. In the case of three of the four cities, however, the deficits are of very substantial proportions. Those municipal deficits will require either outside assistance, local tax increases, or potentially significant reductions in the level of services provided. At both the county and municipal levels, service reductions or tax increases may aggravate the congestion, housing and other difficulties experienced during construction.

Once a power plant comes on line, local county governments receive a significant increase in tax revenues from the utility. Without a mechanism to permit borrowing against these revenues, the county and municipal governments

Table V-5. County and municipal fiscal effects -- Four Eastern Shore Counties

	Year	Revenues	Costs	S/(D)*	Revenues	Costs	S/(D)	Revenues	Costs	S/(D)	Revenues	Costs	S/(D)
COUNTIES		Kent			Queen Annes			Dorchester			Wicomico		
	1	34,331	33,049	1,282	26,345	34,416	1,929	41,132	34,345	6,787	42,167	35,222	6,945
	2	68,542	71,444	(2,902)	52,874	55,565	(2,691)	86,115	73,672	12,443	91,713	78,655	13,058
	3	258,143	288,154	(30,011)	195,603	207,276	(11,673)	349,551	324,287	25,264	385,926	351,507	34,419
	4	476,233	527,611	(51,378)	352,652	383,193	(30,541)	689,182	652,584	36,598	757,969	712,187	45,782
	5	736,444	882,625	(146,181)	563,774	631,255	(67,481)	1,002,180	950,469	51,711	1,082,893	1,047,824	35,069
	6	735,606	912,716	(177,110)	565,196	650,074	(84,878)	1,010,024	982,903	27,121	1,116,751	1,088,766	27,985
	7	544,177	569,794	(25,617)	430,329	392,573	37,756	789,082	730,474	58,608	811,321	679,018	132,303
	8	332,679	183,011	149,668	281,665	130,555	151,110	551,530	197,790	353,740	484,427	216,203	268,224
	9	247,222	49,334	197,888	223,063	37,477	185,586	459,706	50,219	409,487	345,399	55,059	291,340
MUNICIPALITIES		Chestertown			Centreville			Cambridge			Salisbury		
	1	1,856	2,965	(1,009)	897	1,694	(797)	5,971	10,960	(4,989)	3,873	6,256	(2,383)
	2	3,947	6,273	(2,326)	1,906	3,433	(1,527)	13,228	24,085	(10,857)	8,376	13,469	(5,093)
	3	15,425	26,092	(10,667)	7,536	14,765	(7,229)	58,456	106,487	(48,031)	37,555	61,629	(24,074)
	4	30,127	47,601	(17,474)	14,132	27,319	(13,187)	123,612	215,198	(91,586)	76,253	126,027	(49,774)
	5	49,869	81,638	(31,769)	24,454	44,908	(20,454)	188,902	316,667	(127,765)	111,665	187,301	(75,636)
	6	50,073	84,702	(34,629)	24,482	46,355	(21,873)	189,801	329,017	(139,216)	113,651	195,786	(82,135)
	7	37,376	53,195	(15,819)	19,582	27,055	(7,473)	165,403	207,049	(41,646)	89,899	123,164	(33,265)
	8	23,177	17,210	5,967	14,563	9,455	5,108	138,682	66,634	72,048	63,942	39,386	24,556
	9	17,761	4,680	13,081	12,615	2,765	9,850	128,684	16,698	111,986	53,663	10,079	43,584

* S/(D) = Surplus/(Deficit)

Table V-6. Projected deficits due to plant construction -- Four Eastern Shore Counties

County or Municipality	Maximum Deficit % of Current Property Tax Revenues	Maximum Deficit as % of Total Revenues
Kent	6.6%	4.0%
Queen Anne's	2.8%	1.9%
Dorchester	Surplus	Surplus
Wicomico	Surplus	Surplus
Chestertown	23.7%	13.8%
Centerville	41.4%	21.3%
Cambridge	18.3%	13.3%
Salisbury	3.7	2.9%

cannot reduce the fiscal strains which some jurisdictions may experience during construction.

The revenues received by local governments once a plant begins to operate do provide new flexibility in the options available to the locality, including capital improvements, housing upgrading, expanded social or service activities, and reductions in tax rates. For example, Table V-7 gives the tax receipts estimated for the four Eastern Shore counties (3). The variation in these tax receipts is largely the result of variations in tax rates among the counties.

Due to the very high capital cost of modern base-load units, tax receipts from these facilities tend to be substantial. As indicated by the comparison between tax revenues and current county budgets shown in Table V-7, the tax revenues received from a power plant can dwarf other revenues and expenses in the budget of a rural county. It is not uncommon in such cases for the county to reduce tax rates significantly, which has the effect of reducing power plant tax revenues as well.

Table V-8 gives the revenues received by all Maryland counties from electric utilities (5). Table V-8 also indicates the size of the revenue increase relative to the existing county budgets. These tax payments vary substantially, and depend largely on the nature and age of the facilities owned by utilities in each county, as well as on local tax rates. The presence of power plants in Anne Arundel, Baltimore, Calvert, Montgomery, and Prince George's Counties and Baltimore City are evident in the tax receipts of these counties. The impact of a large facility on the budget of a largely rural county is most evident in Calvert County. However, even the presence of an older plant in a rural county has some impact, as may be seen in the cases of Charles and Dorchester Counties.

G. Summary

In summary, power plant construction in Maryland is not likely to induce the kind of boomtown effects experienced by western energy development. Depending on the size, location, and infrastructure of the county in which power plant development does occur, however, significant effects may be experienced in the area of housing, traffic congestion, and local population changes. In all jurisdictions, gains in personal income and business sales are likely. Local government budgets and service requirements may increase, but the size of the increase and any potential budget imbalances will vary substantially between counties. In some instances, particularly at the municipal level, the magnitude of the potential imbalance could lead to a deterioration of services or to the necessity of raising new revenues to cover potential deficits.

Table V-7. County revenues, operating period -- Four Eastern Shore Counties

County	Revenues	As % of Current Budget
Kent	36,000,000	650%
Queen Annes	27,000,000	390%
Dorchester	40,000,000	450%
Wicomico	28,000,000	140%

Table V-8. Total taxes paid to Maryland Counties by Maryland utilities, fiscal year 7/1/77 - 6/30/78

County	Utility Total Taxes Paid to County	Utility Tax Payments as % of County Budget
Allegheny	266,121	1.2
Anne Arundel	4,488,153	2.0
Baltimore City	17,983,231	1.7
Baltimore County	9,152,877	2.8
Calvert	11,552,445	48.1*
Caroline	151,105	2.7
Carroll	654,042	2.3
Cecil	643,978	3.8
Charles	3,765,579	15.1
Dorchester	780,364	8.7
Frederick	1,315,699	3.6
Garrett	260,305	3.3
Harford	2,696,904	4.8
Howard	1,303,675	2.2
Kent	168,017	3.1
Montgomery	14,165,565	2.7
Prince Georges	14,327,239	3.5
Queen Annes	120,946	1.7
St. Marys	30,485	0.2
Somerset	133,826	3.3
Talbot	81,058	0.9
Washington	770,835	2.7
Wicomico	384,651	1.9
Worchester	254,459	1.8

* If adjusted for one-time capital expenditure out of current expenses budget this figure would increase to 72.2%

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5. Data provided by J. Nicol, APS; M. Hinkle, BG&E; R. Bryson,Conowingo; J. Pflieger, DP&L; M. Gould, PEPCO; D. Sturtevant, Maryland Association of Counties.

CHAPTER VI

OTHER IMPACTS

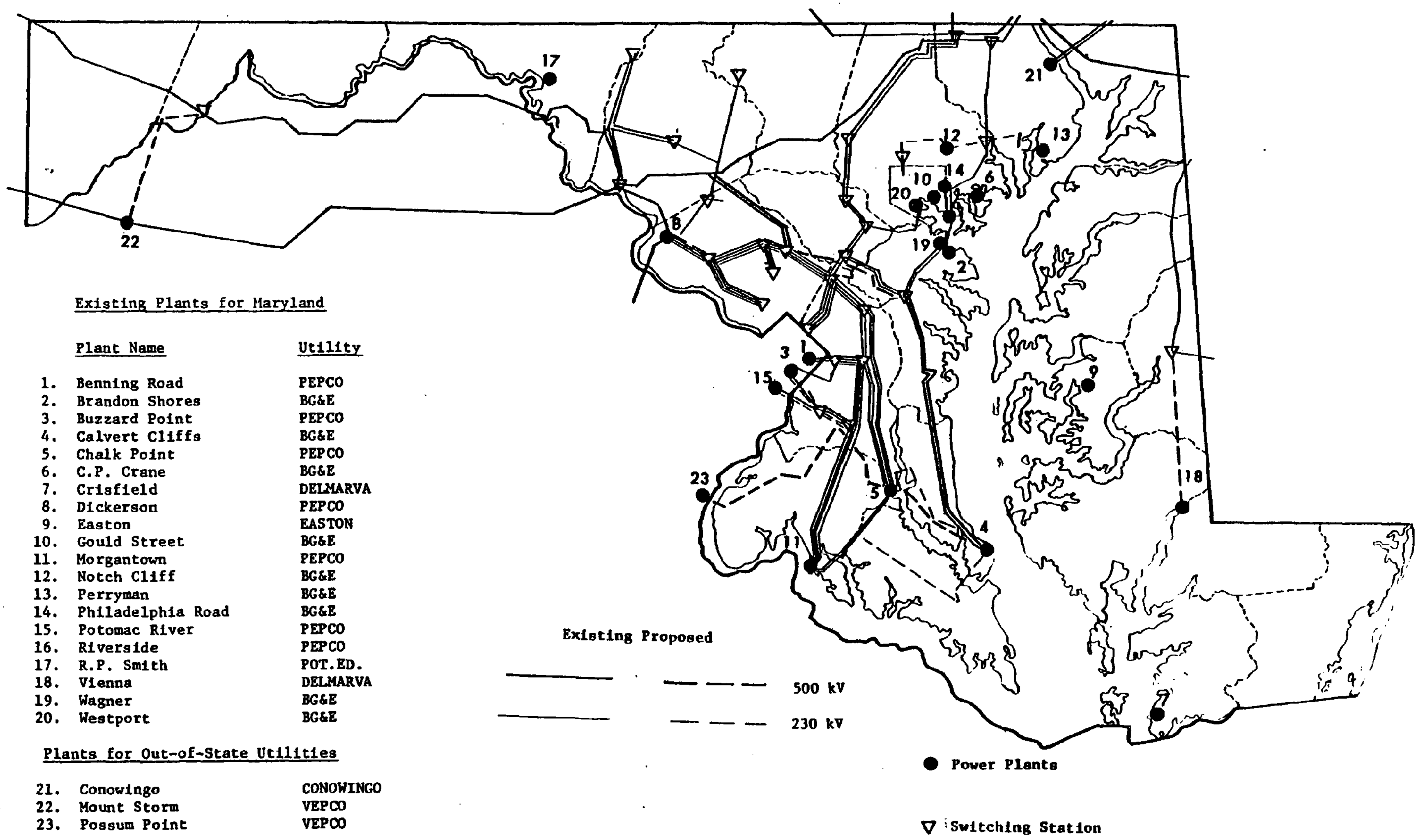
A. Transmission Lines

Electrical power is carried from generating stations to the users of electricity by a system of power lines, transformers and switching stations. The higher voltage lines, called "transmission lines," connect generating stations to each other and to major transformer substations located near load centers. Figure VI-1 depicts the transmission system in Maryland. All power lines above 69,000 volts in the State are designated as transmission lines, and the highest voltage currently used or planned for use in the State is 500,000 volts (Table VI-1). Power lines carrying 69,000 volts or less are designated as "distribution lines." They form a grid system throughout each service area, connecting each consumer of electricity to the transmission lines and hence to the generators.

Several types of impacts may be associated with power lines. Ecological impacts, both positive and negative, may result from the clearing created to permit the passage of power lines through natural areas. Aesthetic impacts may occur when direct view of the lines or their clearings interfere with the other elements of the natural visual scene. Physical effects caused by the electrical fields near higher voltage transmission lines include spark discharges and currents to which a person may be subjected if he touches an ungrounded metallic object. Audible noises are also generated by these electrical fields, such as "sizzling" sounds produced by 500,000 and some 230,000 volt lines, and discrete tones ("60 cycle hum") produced by transformers and some higher voltage lines. Radio and television interference may be caused by the corona discharges on high voltage lines and by loose connections which cause sparking in lower voltage equipment. Health effects from the oscillating electrical field under high voltage lines have recently been alleged, and are presently the subject of much national debate and study.

The magnitude of each of these effects depends upon the voltage carried by the power line, the design of the line's conductors and towers, and the location and situation of the line. The visual surroundings, the extent, type and proximity of nearby human activities, the strength of commercial radio and television signals in the area, and the nature of the local ecosystem are all factors which will determine the extent and severity of adverse effects. In general, the potential for adverse effects increases as the voltage of the power line is increased. Higher voltage lines create greater electric fields, stronger radio frequency emissions, and require larger, more visible towers and wider clearings for rights-of-way. Balanced against these effects is a reduction in the number of transmission lines needed to carry the given amount of power.

Ecological impacts of power lines can largely be mitigated by proper routing to avoid unusually sensitive or unique areas, by careful sedimentation



Existing Plants for Maryland

	Plant Name	Utility
1.	Benning Road	PEPCO
2.	Brandon Shores	BG&E
3.	Buzzard Point	PEPCO
4.	Calvert Cliffs	BG&E
5.	Chalk Point	PEPCO
6.	C.P. Crane	BG&E
7.	Crisfield	DELMARVA
8.	Dickerson	PEPCO
9.	Easton	EASTON
10.	Gould Street	BG&E
11.	Morgantown	PEPCO
12.	Notch Cliff	BG&E
13.	Perryman	BG&E
14.	Philadelphia Road	BG&E
15.	Potomac River	PEPCO
16.	Riverside	PEPCO
17.	R.P. Smith	POT.ED.
18.	Vienna	DELMARVA
19.	Wagner	BG&E
20.	Westport	BG&E

Plants for Out-of-State Utilities

21.	Conowingo	CONOWINGO
22.	Mount Storm	VEPCO
23.	Possum Point	VEPCO

Figure VI-1. Power plants and transmission lines in the Maryland region

Table VI-1. Pole miles of transmission lines and circuit miles of underground cables in Maryland

Existing or under construction as of December 31, 1977, per annual reports to the Maryland Public Service Commission

Utility	Line Voltages 500 kV	230 kV	138 kV	115 kV	69 kV	Existing Corridors (Acres)
BG&E						
Pole Miles	195.7	214.6 [a]	15.3	333.4	-	9,698
Und. Cable	-	-	-	58.9	-	
PEPCO						
Pole Miles	52.4	341.5	-	- [c]	-	5,997
Und. Cable	-	16.3	48.2	11.7	-	
Conowingo						
Pole Miles	24.1	1.7 [c]	2.4 [d]	-	-	925
Und. Cable	-	-	-	-	-	
Susquehanna						
Pole Miles	-	13.9 [c]	-	-	-	930
Und. Cable	-	-	-	-	-	
Delmarva						
Pole Miles	-	61.0	125.7	-	311.6 [e]	7,209
Und. Cable	-	-	-	-	-	
Pot. Edison						
Pole Miles	90.4	72.8	260.5	-	17.7	6,760
Und. Cable	-	-	-	-	-	
Southern Md.						
Pole Miles	-	-	-	-	264.6	3,379
Und. Cable	-	-	-	-	0.3	
TOTALS						
Pole Miles	362.6	705.5	403.9	333.4	593.9	34,898
Und. Cable	-	16.3	48.2	70.6	0.3	

(a) Plus 6.4 circuit miles of sub marine cable.

(b) Plus 26.4 miles on structures of another line.

(c) 200 kV

(d) Plus 2.1 miles on structures of another line, all voltage 132 kV

(e) Plus 0.6 miles of submarine cable

and erosion control practices during construction, and by selective clearing and maintenance. Right-of-way maintenance for enhanced wildlife productivity is possible for some species which require grasses, dense brush or edge habitats. Where power lines traverse areas that are otherwise solidly forested, power line corridors may actually increase the diversity of species. Other species, however, particularly those requiring mature trees or forests, can only have their available habitat decreased by power line rights-of-way. Where power line corridors open otherwise secluded areas to human traffic, particularly noisy traffic such as motor bikes, all-terrain vehicles and snowmobiles, habitat may become unacceptable to timid species and erosion may be caused by vehicular traffic. These impacts must be evaluated on a case-by-case basis.

Aesthetic impacts are subjective but no less significant. Selective clearing and vegetative screening can mitigate visual intrusion in natural areas, but it is usually not possible to hide power lines completely from human view. A trade-off arises between routing a line through a more secluded area, where less people see it but the aesthetic impact per person is high, and routing it along a more populated urbanized corridor which is already visually impacted but where more people will see it. The effects such views create on property values have not yet been quantified for the various types of residential settings and power line configurations in Maryland. Residential situations vary from low cost row housing to estates situated near focal points of natural scenic beauty. Transmission lines range from single wooden poles carrying three wires, to bridgework tower structures over 150 feet tall, carrying bundles of wires. Again, impacts must be considered case by case.

Radio interference, audible noise, and ozone production are all caused by corona discharges which occur when the local electric field strength at the surface of the transmission line wires exceeds the breakdown potential of the air. These effects are particularly noticeable in wet weather when water droplets on the conductors increase corona discharge.

Audible noise consists of a "sizzling" sound in wet weather and a barely audible crackling noise in dry weather. For example, during wet weather, one 500 kV double circuit line reached a level of 43 dbA* near the transmission line ROW, and 30 dbA (corresponding to the background noise in a very quiet rural area at night) at a distance of 200 ft from the ROW (1). The 43 dbA level is considerably below the Maryland State Limit of 50 dbA (night), although the possibility of annoyance cannot be absolutely ruled out. Under wet weather conditions, ambient noise levels are exceeded at high frequencies (above 500 Hz) at locations close to the line. Fortunately, the higher frequencies characteristic of transmission line noise are more rapidly attenuated with distance (1).

Radio interference (RI) is a collective term for the various types of electromagnetic interference. RI from power lines is caused by corona discharge, an effect that is particularly important in wet weather. In such

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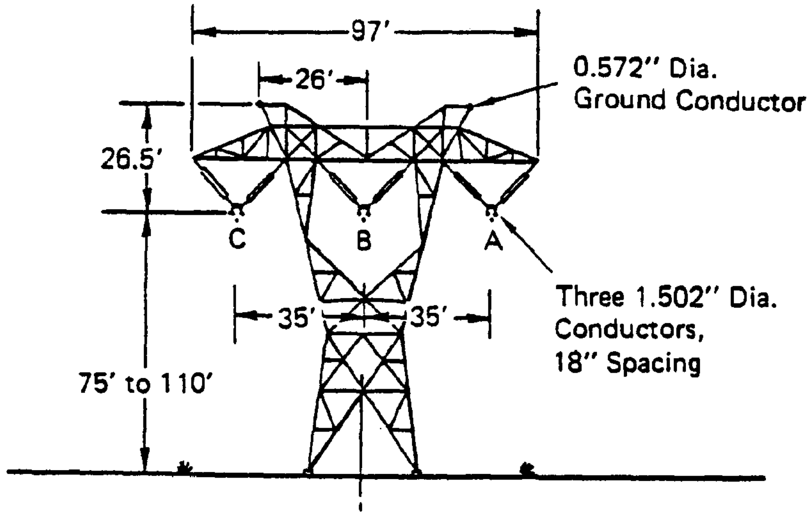
* dB or decibel is a relative measure, here equal to the logarithm of the ratio of a measured energy to some reference energy. dBA is the total energy over a frequency band similar to that perceived by the human ear, referenced to a pressure of 2×10^{-4} μ bars = 20 μNm^{2}.

conditions, it may be bothersome for AM reception for residents located close to the line (1). During fair weather, residents nearby the ROW experience minimal interference. For example, investigations (2) involving the proposed Brighton-High Ridge 500-kV line indicate that at least 18 AM radio stations would maintain an acceptable signal-to-noise ratio (21 dB). During light rain and heavy fog, residents extremely close to the ROW (less than 100 ft) for this line may notice a degradation in signal quality, but between 5 and 10 radio stations would still be available at an acceptable quality level. During heavy rain (a condition which often brings electrical interference of its own), interference effects extend to greater distances, but between 2 and 7 radio stations would still be available at distances of 100 feet from the ROW (2).

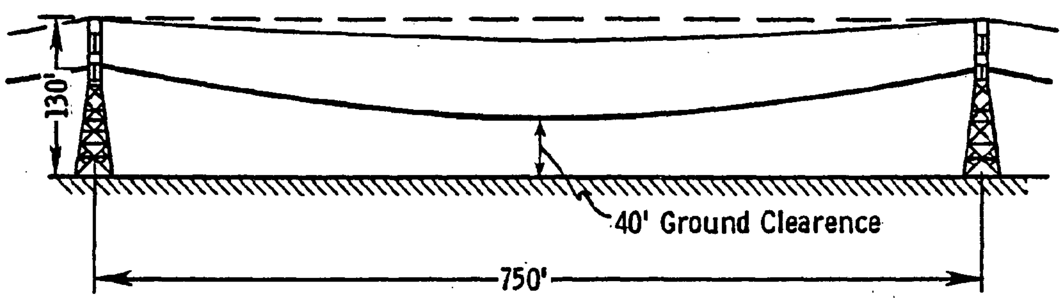
Studies indicate that TV interference would not be bothersome, except possibly for sets located close to the ROW (< 300 feet) using indoor antennas (rabbitears) tuned to a weak, low wavelength station (channels 2-6) during a heavy rainstorm. In most cases, installation of a directional, outdoor antenna would eliminate this problem (1,2). For FM broadcasts and higher wavelength TV reception (channels 7-13 and UHF), no significant interference is expected outside the ROW.

Corona processes from EHV power transmission lines also produce ozone by a method analogous to that occurring during lightning discharges. Several laboratory programs and modelling efforts have investigated the corona production and dispersion processes (1). The efficiency of the production rate varies widely with line voltage, electric field strength, conductor geometry and condition, and meteorological conditions around the transmission lines. On very humid days (but without precipitation), with clean conductors, and with conductor configurations designed to minimize the electric field strength, corona loss and ozone production will be reduced. During heavy rain, with nicked or contaminated conductor surfaces, corona loss and ozone production will be increased. Laboratory measurements have determined that ozone is generally produced at a rate of 0.5 to 5 grams per kW-hr of corona energy loss, depending on conditions (1). Field studies (as reviewed in Ref. 1) have either failed to detect ozone contributions due to transmission lines or have, under worst case conditions, averaged less than 1 ppb above peak background fluctuations. Based upon these results, it is reasonable to conclude that ozone production from transmission lines is not expected to have any significant effect on the local or regional environment.

Electric and magnetic fields are generated around an operating power line. Magnetic fields are present any time current flows in the line, but the magnitude of these fields is small and their effects negligible when compared to the effects of electric fields, which can induce charges on metallic surfaces such as vehicles, gutters on adjacent structures, fences, and masts of sailboats. People touching these objects may draw a steady current through their body or may be subjected to spark discharges upon approaching these objects. The magnitude of the electric field varies with location, conductor height, and the configuration of the line. For example, for the line configuration shown in Figure VI-2, the maximum field intensity varies from about 7.0 kV/m at the minimum clearance point to below 3 kV/m at conductor heights above 65 feet (Figure VI-3). For all heights, the field at the edge of the ROW would be below 2.5 kV/m.



a) Lattice Structure



b) Example Span Profile

Figure VI-2. Typical 500 kV transmission line

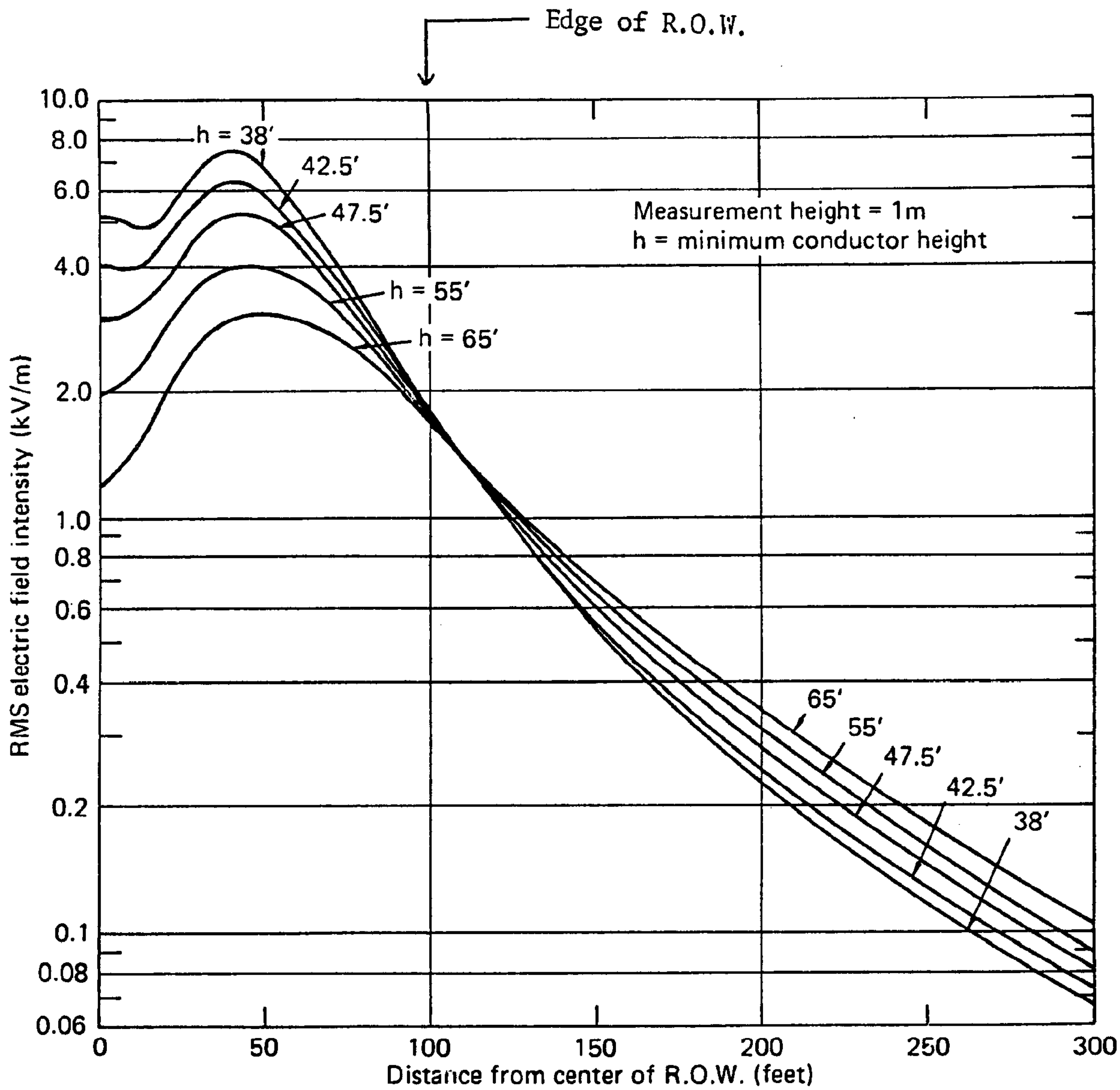


Figure VI-3. Electric field profile for 500 kV horizontal configuration with three sub-conductors

The magnitude of these effects has been calculated for several representative "worst case" situations assuming a typical 500 kV power line configuration (1). Effects depend on the distance to the transmission line and the size and orientation of the object causing the effect on the human. In field tests, actual observed effects have varied from 10 to 100 percent of the calculated "worst case" results, reflecting the fact that many unknown and uncontrollable factors (such as insulation or leakage resistance under different conditions of soil, vegetation, and moisture content, and capacitance of irregular objects) are of central significance. Effects to quantify these factors (allowing a more realistic risk assessment) are now in progress (3). Figures VI-4 and VI-5 give the maximum "worst case" induced currents and spark discharge currents for various objects exposed to the fields surrounding the line depicted in Figure VI-2. Also shown in the figures are the range of human responses. The "let-go" current is the level at which a person is unable to release his grip on a conductor. This level, obviously, is considered to be potentially dangerous. Another possible hazard is that a spark discharge may cause ignition during fueling of a vehicle under a transmission line near midspan. Figure VI-6 shows ignition potential for some typical vehicles when located in the maximum "worst case" electric field at the point of minimum height (40 ft) for the line shown in Figure VI-2 (note that a tractor-trailer normally will use diesel fuel not subject to ignition under these conditions). Actual tests have shown that the chances of such ignition are extremely remote, but it is nevertheless good practice not to refuel under a transmission line. The Power Plant Siting Program has recommended, as a result of these calculations, that the minimum height of new 500 kV lines over roads be raised to about 50 feet (depending upon configuration) so that refueling a vehicle the size of a school bus will not entail any risk of fuel ignition.

Questions have been raised concerning the health effects of chronic exposure to oscillating electric fields at magnitudes found within (or possibly adjacent to) transmission line rights-of-way. Soviet literature contains reports of medical evaluations of personnel working in 400 kV to 765 kV switchyards. A majority of those studied developed pathological reactions attributed to their exposure to the electric fields. As a result, Soviet work regulations limit the time a worker may be exposed to fields equal to or in excess of 5 kV/m. Maximum field intensities from some 500 kV lines currently in use in Maryland may reach peak intensities within the right-of-way of 6.7 kV/m at a height of 1 meter above the ground, and 7.5 kV/m at a height of 3 meters above the ground. These peak intensities occur at the lowest point of conductor sag. The Soviet work rules would limit a person's exposure to such fields to 3 hours per day. In contrast to the Russian reports, a major U.S. study of the medical effects of 10 linemen (4), working with 138 kV and 345 kV equipment over a 9-year period, concluded that the health of these men had not been affected by their exposure to the high-voltage lines.

The question of the health effects of exposure to 60 Hz electric fields is under study by many researchers (5). Both the Energy Research and Development Administration and Electric Power Research Institute are sponsoring major research programs to determine the long-term chronic health effects of exposure to electric fields. At the present time, safe limits for exposure to electric fields from transmission lines have not been established in the

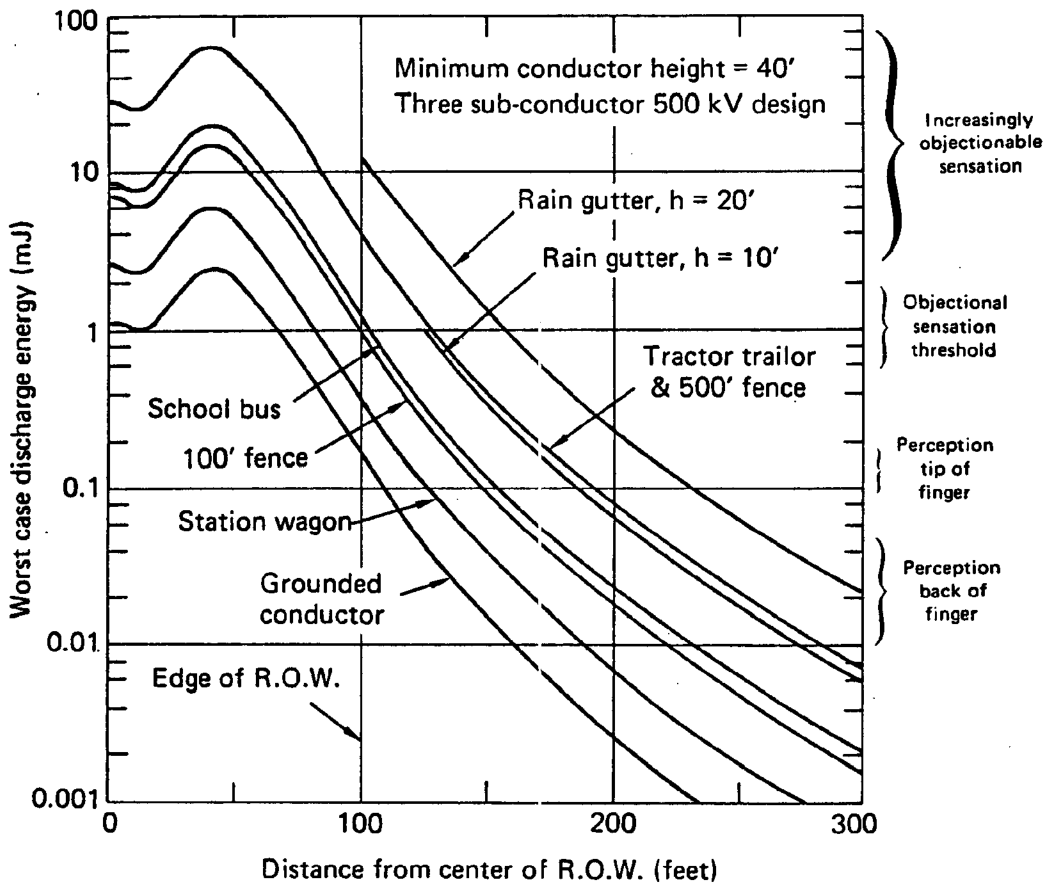


Figure VI-4. Worst case electrostatically induced spark discharge for people touching various objects

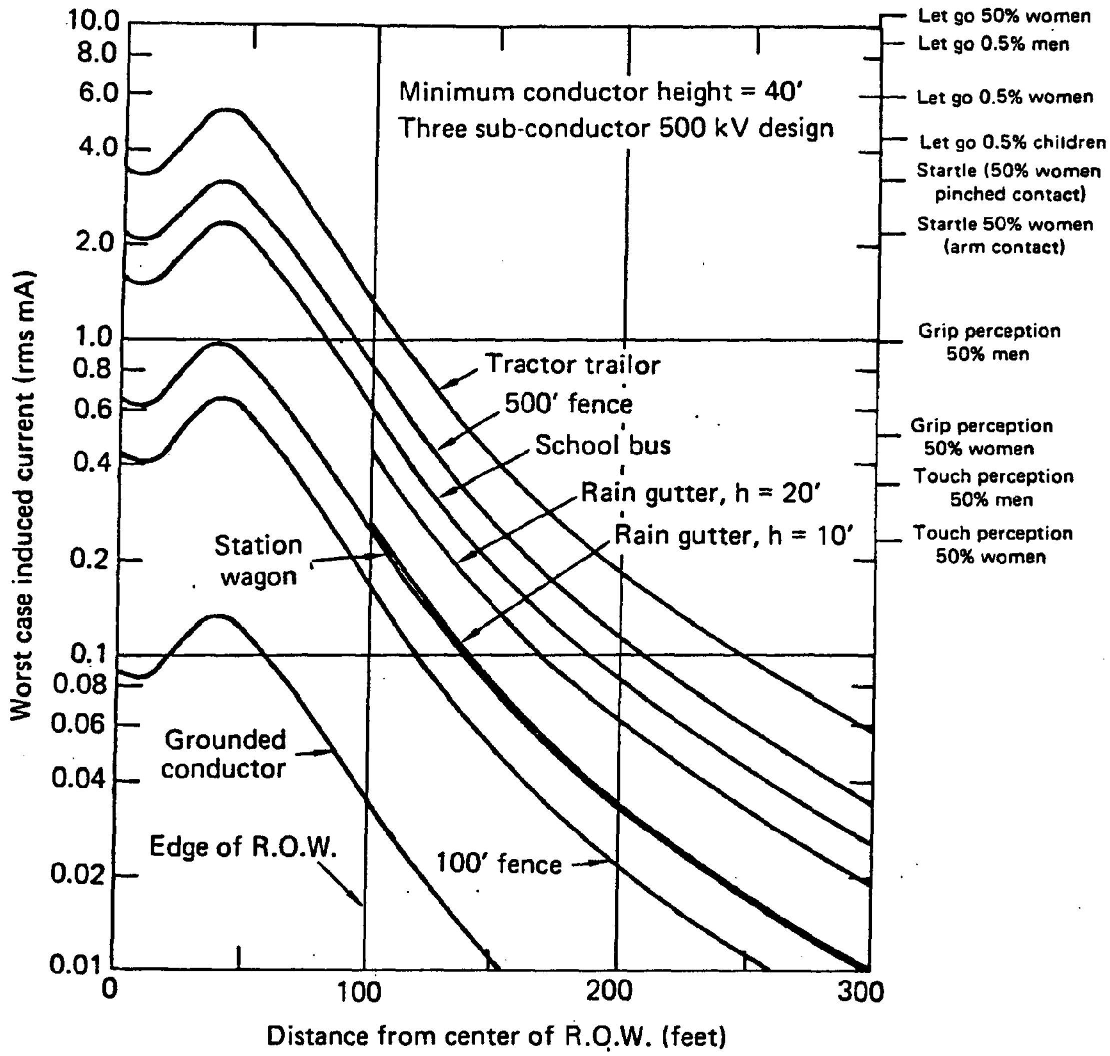


Figure VI-5. Worst case electrostatically induced currents for people touching various objects

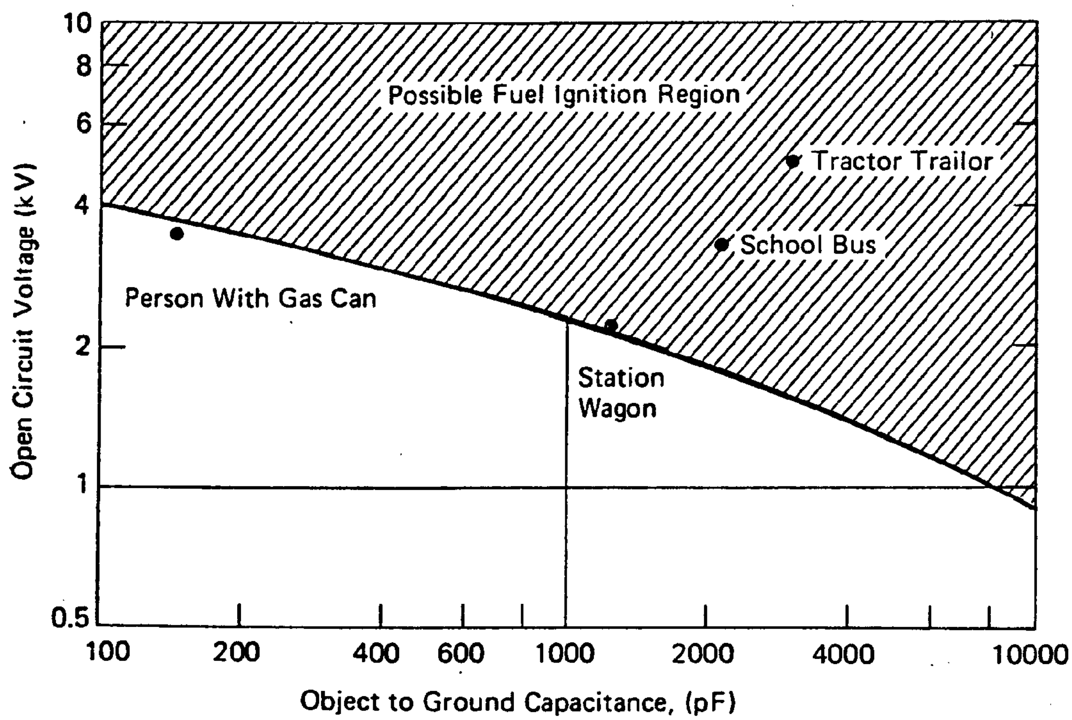


Figure VI-6. Gasoline ignition potential from AC spark discharges. (Test results obtained on a warm, dry day.) Points apply to worst case open circuit voltage under proposed 500 kV line. Minimum conductor height = 40 feet

U.S. Several factors should be appreciated in evaluations of available literature on transmission line health effects:

- Neither Soviet nor U.S. reports on health of linemen and switchyard workers present adequate test data or discuss control procedures.
- Linemen and switchyard workers may be exposed to higher fields (up to 25 kV/m) then would be experienced by other people under the transmission lines.
- Generally, levels of the electric field from transmission lines along the ROW are below levels at the lowest point of conductor sag.
- Exposure to the highest field intensity occurs only when a person is almost directly under one of the conductors. Within the ROW, the average intensity is lower.
- Beyond the edge of the ROW, intensities drop rapidly below peak levels. It is in this reduced intensity region that residents would be likely to receive extended exposure.

Table VI-1 summarizes the status of transmission lines in Maryland. Since the last CEIR, several changes have occurred. First, BG&E has upgraded their low-level (115-138 kV) transmission system substantially. PEPCO has started work on a 500 kV distribution loop around Washington, D.C. Finally, Delmarva has completed 61 miles of their 230 kV distribution loop for power distribution on the Delmarva peninsula. These trends in upgrading voltage and distribution nets are expected to continue.

Conclusions

The routing of transmission lines deals with effects that may have aesthetic, ecological, health, and physical implications. The aesthetic effects generally involve trade-offs between rural and urban routes. Ecological effects can be both positive and negative and must be evaluated on a case-by-case basis. The electrical effects are now well understood and are potentially significant only for locations within or extremely close to the ROW. The health effects remain an area of controversy, mainly due to differing medical results from U.S. and Soviet studies in this field.

While the dangers to personal safety are relatively remote for anyone who is only occasionally in the proximity of transmission lines, the Maryland Power Plant Siting Program has taken steps to reduce that risk even further, so that the possible hazards from transmission lines, except under highly unusual conditions, are virtually negligible.

B. Groundwater

In addition to the need for cooling described in the aquatic chapter, power plants also require freshwater for boiler make-up, pump cooling, sanitary water supply, and pollution control equipment. These uses can be considerable - up to 1.6 million gallons daily for 2000 MW of fossil-fueled capacity and 500,000 gallons daily for a 2000 MW nuclear plant. This water can be drawn from four sources, depending upon the plant location.

- Non-tidal river - Usually, the water is withdrawn from the river and purified for use. Examples of plants using this type of withdrawal are Dickerson and R.P. Smith.
- Industrial water supply - Large cities like Baltimore and Washington provide water of industrial quality to power plants and other large users.
- Groundwater/Desalination - For plants located near brackish surface water, but remote from municipal supplies, there are two alternatives: to desalinate the surface water or to use groundwater. For four of the Maryland plants (Morgantown, Chalk Point, Calvert Cliffs, and Vienna), the choice has been to use groundwater. The potential impact of these wells on adjacent users is discussed below.

A generalized cross section of the coastal plain sediments, shown in Figure VI-7, indicates the water-yielding formations ("aquifers") available for groundwater withdrawals in Southeastern Maryland. The potential impact of the use of groundwater lies not so much in a reduction of the quantity of water available, but in a decrease in the hydraulic head or "potentiometric surface" in the area surrounding the point of withdrawal. This surface represents the level to which the water would rise if a well were drilled into the aquifer in question. As the well is pumped, a "cone of depression" centered around the well is created in this surface. If pumpage lowers the surface below the intake level of the pump of a neighboring well in the same aquifer, then that well becomes "dry". In such a case, the pump would have to be lowered to a depth that would remain below future lowerings of the potentiometric surface.

The Calvert Cliffs plant has 3 wells averaging 620 feet in depth that withdraw water from the Aquia aquifer (6). The average monthly usage (Figure VI-8) is far below the allowed average and maximum appropriations of 600,000 gpd and 865,000 gpd, respectively (6). Water levels in an observation well located about a quarter mile from the plant have declined approximately 10 feet due to pumpage (Figure VI-8) (7). No significant lowering would be expected outside the plant property due to this pumping (8). Several other users in the area (e.g., U.S. Naval Research Laboratory, Patuxent Naval Air Center, Randle Cliffs) use similar or larger amounts of groundwater from the aquifer (6).

The Vienna plant draws from 5 wells, four of which are screened in an unconfined aquifer (Quaternary) (35-54 feet) and the other of which draws

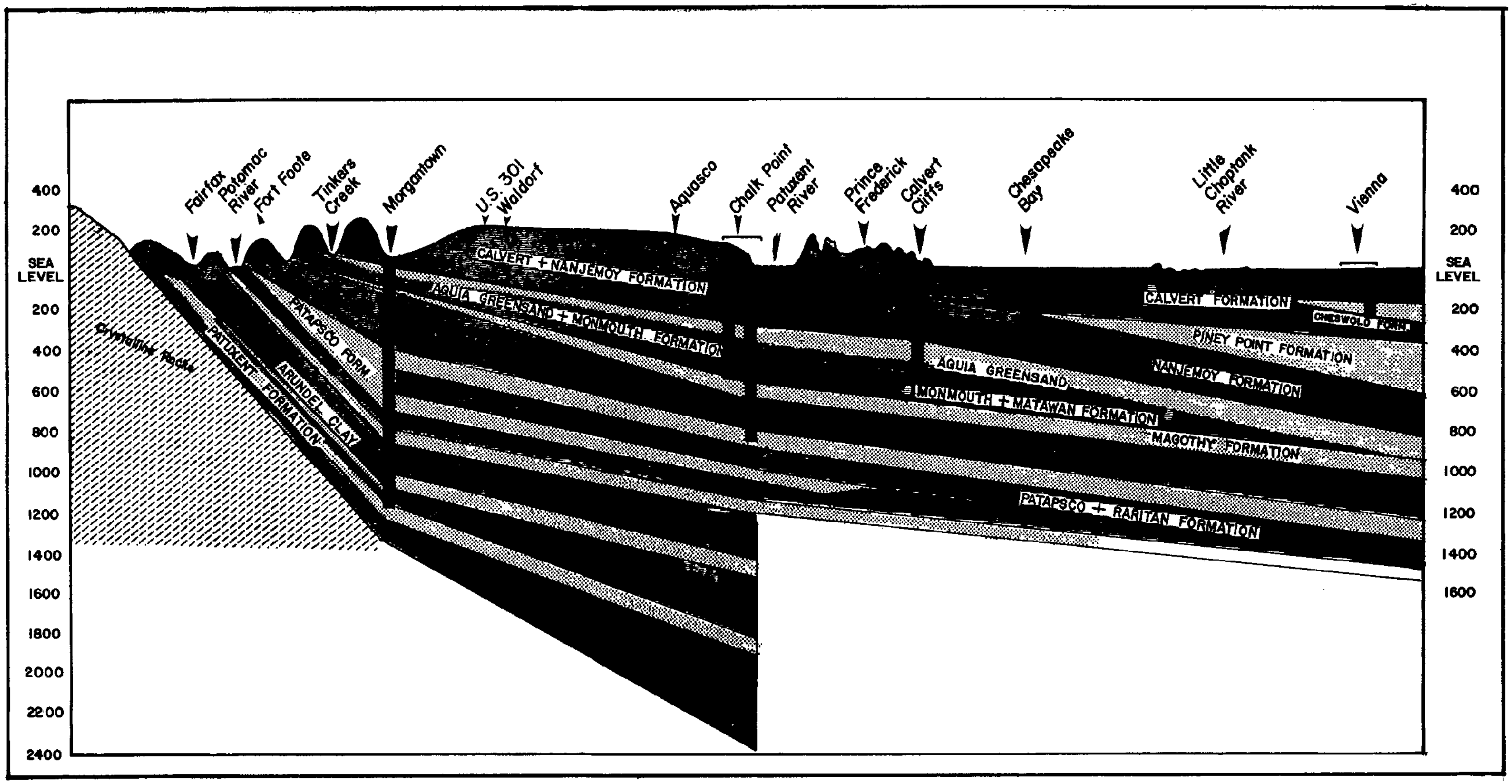


Figure VI-7. General cross-section through unconsolidated coastal plain sediments in Southeastern Maryland

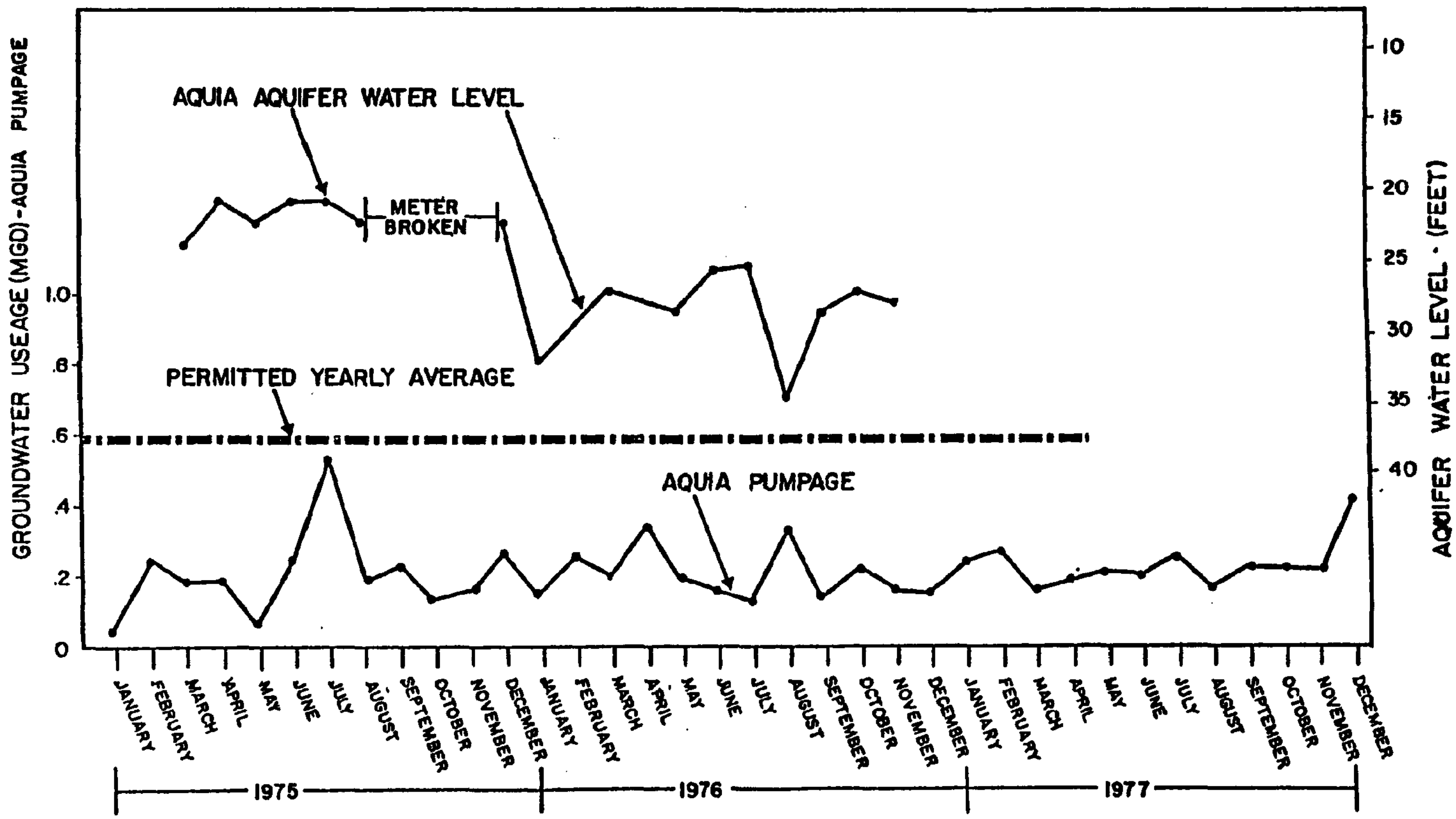


Figure VI-8. Pumpage and water levels of the Aquia aquifer at the Calvert Cliffs Nuclear Plant from the Cheswold aquifer (310 feet) (6,9). The average withdrawal rate for both aquifers is shown in Figure VI-9. Average withdrawal decreases during winter periods because the Nanticoke River is used as a supplemental fresh water supply (9). Because the Quaternary aquifer is likely recharged on an annual basis directly from precipitation and possibly seasonally from the Nanticoke River (5), the pumpage is expected to have no long-term effect. However, nearby domestic wells could be impacted on a seasonal basis (i.e. during periods of little recharge and heavy pumpage) (10). The town of Vienna supplies most of the local domestic water from the Cheswold aquifer (45,000 gpd). Overall groundwater usage at this plant will increase by about 220,000 gpd in the 1980's if a proposed 400 MW expansion is constructed (11). This increase will be partially offset by retirement of the existing once-through units. The detailed investigations needed to characterize the ground-water resources in this area are now in progress (12).

The Morgantown plant has 5 wells, averaging 1100 feet in depth, that withdraw water from the Patuxent aquifer (6). The average withdrawal (Figure VI-10) is eight hundred thousand gallons daily (6). Water levels of the Patuxent aquifer have declined 80-90 feet (13), as measured by an observation well near the plant. Water levels of the upper aquifers have declined at rates basically unchanged since before PEPCO began pumping, indicating that the plant is not directly linked to the decline (13). At the request of the Power Plant Siting Program, the U.S. Geological Survey is installing a continuous water-level recorder on an observation well screened in the Patuxent aquifer at this site.

The Chalk Point plant draws from two aquifers, the Patapsco (1066 feet) and the Magothy (630 feet). The average withdrawals, shown in Figure VI-11, indicate that the plant exceeded the permitted yearly average withdrawal for the Magothy aquifer in 1976* (14). Drawdown in the Magothy aquifer due to pumping from the plant (also shown in Figure VI-11) has been consistent since operations began in 1963, reaching a maximum of 55 feet in August/September 1976 (15). The plant does not pump from the upper aquifer (Aquia) used for domestic wells in the area. There are no other users of the Magothy in the immediate vicinity of the plant (< 8 miles). Plant influence can be put in perspective by looking at the effect of these withdrawals on the potentiometric surface in the area. Figure VI-12, a survey (USGS) of the Magothy surface taken during early September, 1977 shows a "cone of depression" near the plant. Similar cones exist near Waldorf (as shown on map), Annapolis, and Severna Park. At present, the impact of these cones upon nearby users appears to be minimal. However, should Waldorf expand its withdrawal rate significantly or another major user locate in the general area, the combined cones may affect users who cannot adjust their well pumps with water level (so-called "telescopic wells") (16). Detailed studies (as required under Title 8 of the Natural Resources Articles and proposed revisions to Water Resources Regulation .08.05.02) would have to be carried out before such expansion would be allowed. The USGS (17) has prepared a model of the Magothy aquifer that can be used to clarify the possible interactive effects of increased usage near the Waldorf-Chalk Point area.

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* There is an unresolved question, whether the maximum monthly average pumpage permit limitation of 2 mgd must be divided between the two aquifers (18,19).

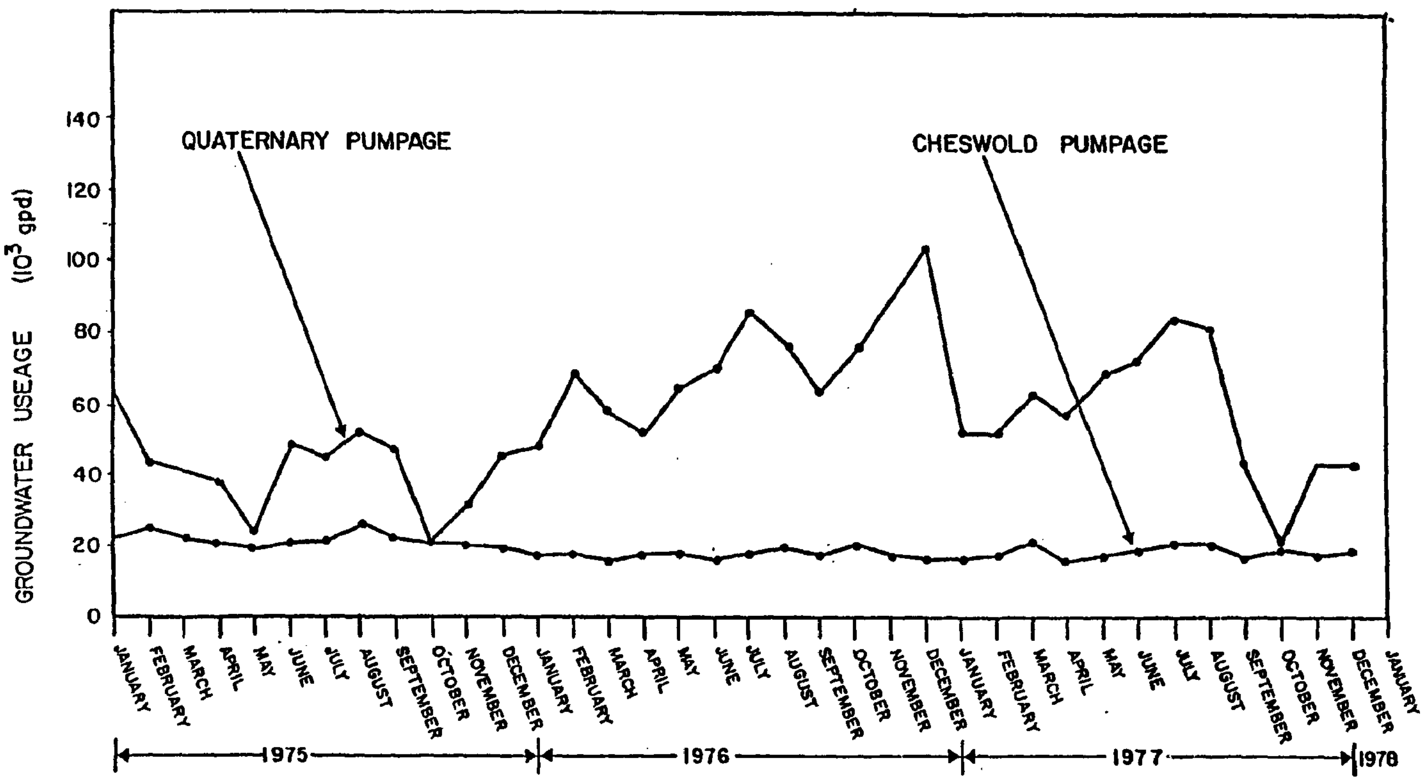

Figure VI-9. Pumpage from the Quaternary and Cheswold aquifers at Vienna Power Plant

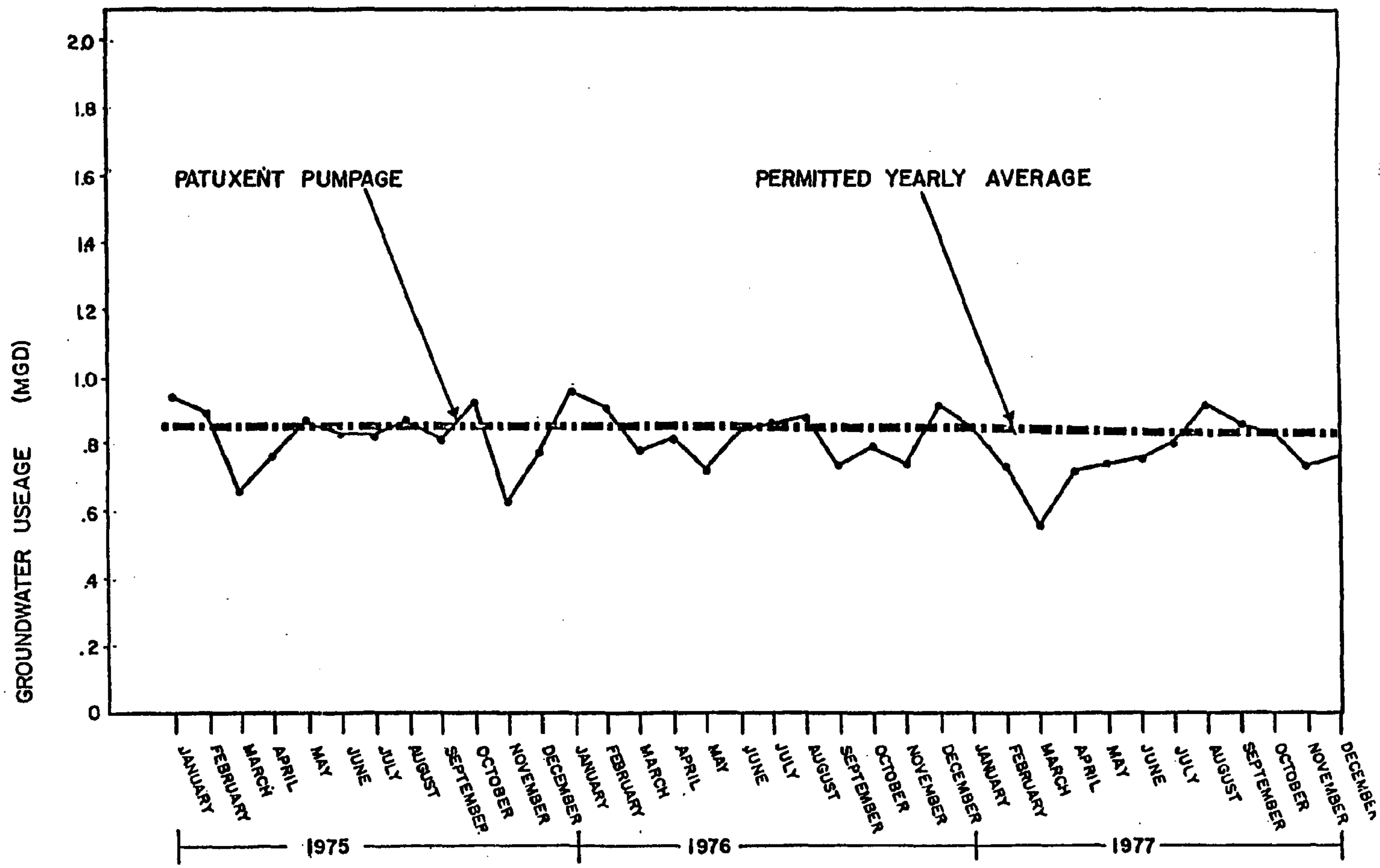

Figure VI-10. Pumpage from the Patuxent aquifer at the Morgantown Power Plant

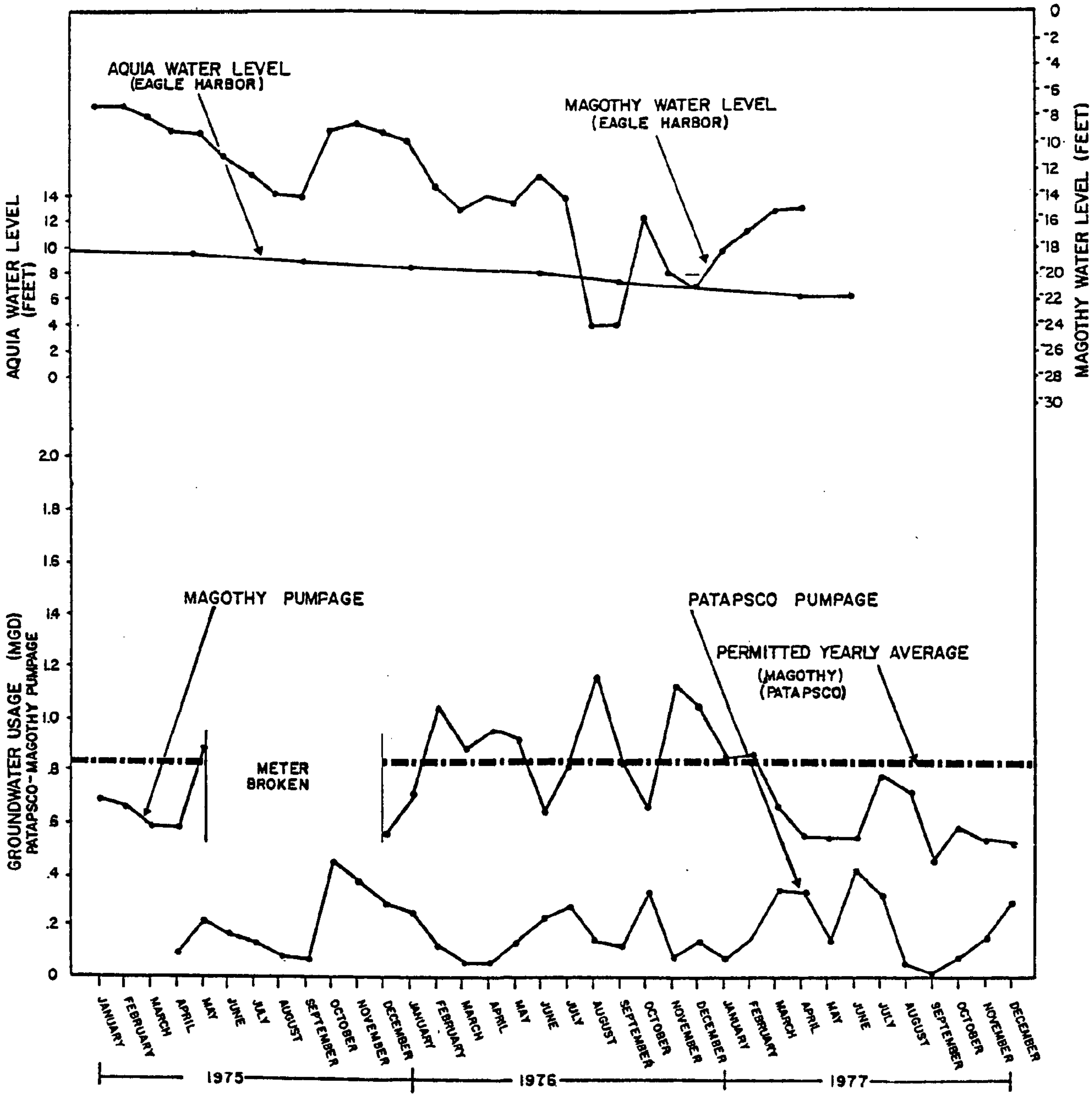

Figure VI-11. Pumpage from the Magothy and Patapsco aquifers at Chalk Point. Also included are water levels at test wells in Eagle Harbor, approximately 2 miles north of the plant

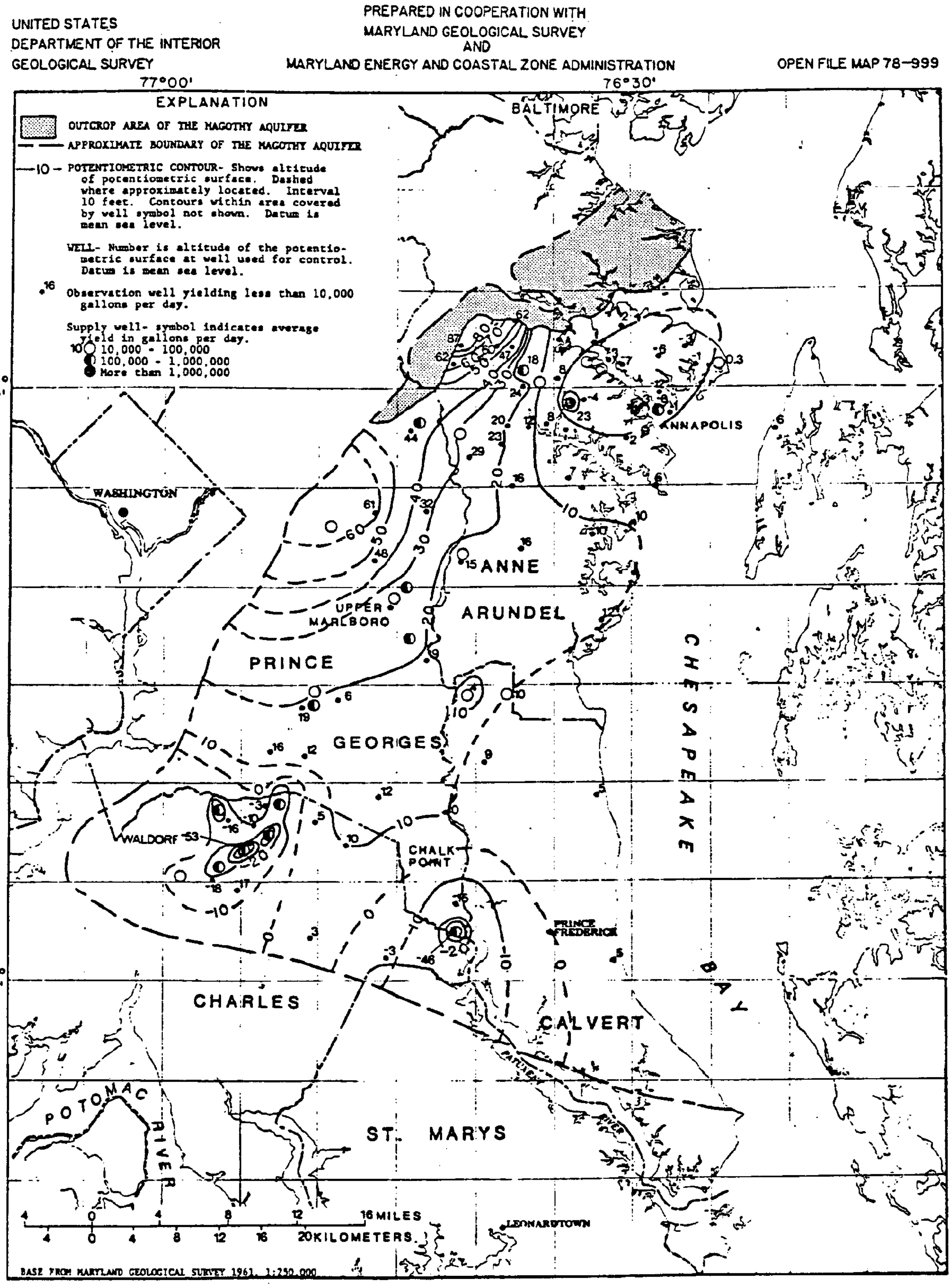

Figure VI-12. Map showing the potentiometric surface of the Magothy aquifer in Southern Maryland, September 1977, by Frederick K. Mack, Judith C. Wheeler, and Stephen E. Curtin, 1978

Conclusions

Although the use of groundwater is relatively large at power plants compared to most other industrial sources, due to the relatively sparse usage of the deep aquifers they have tapped, there has been no significant impact upon present wells near these plants. However, if a major increase in withdrawals from the Magothy aquifer were to occur in the neighborhood of Chalk Point, there could be significant impact upon users of the Magothy aquifer in that area.

C. Cooling Towers

Once-through cooling systems use large amounts of water, typically about 2 cfs per MW for a fossil fuel plant, and almost 3 cfs per MW for a nuclear plant, in both cases for a 10° F temperature rise across the condenser. Although this water does not immediately disappear from the natural water system (eventual consumptive loss for a once-through system is about 10-70% of that for a cooling tower), it may never-the-less be necessary to reduce the intake flow under three conditions:

- If a large water intake causes potentially excessive entrainment losses, (e.g., Douglas Point site on the Potomac);
- If the natural river flow is not sufficient to guarantee adequate cooling flow at all times, (e.g., Dickerson units 4 & 5 on the Potomac River);
- If the cooling water volume is such a large portion of the available natural flow that the heating of the river may be unacceptable, (e.g., as might be the case of a large plant on a small body of water).

The alternative to once-through cooling is a closed loop cooling system, such as cooling towers, spray ponds, and cooling ponds. In Maryland, due to factors such as amount and cost of available land, the preferred alternative is the cooling tower. There are many design options which tailor performance to site-specific needs. Towers can be of two basic types: dry or wet. In a dry tower, the condenser cooling water rejects its heat to the air in a totally enclosed system similar to the cooling system in an automobile. A dry cooling tower requires very large heat exchange surfaces, and is typically not economically feasible for large power plants. A dry system does, however, have the advantage of being the only system where there is no evaporative loss of water. In a wet cooling tower the hot water is brought into contact with the air, and a large proportion of the cooling is accomplished by evaporation, a potentially troublesome situation where consumptive water use is a major consideration (as on the fresh water portion of the Potomac River). The water can be sprayed into the passing air, or more commonly, the air is passed through porous surfaces around or through the area where the water also passes. The air can be moved either by fans (mechanical draft towers) or by natural circulation (natural draft towers). While the use of cooling towers may be beneficial as far as aquatic impacts are concerned, it can introduce adverse impact in the terrestrial environment. Possible impacts may result from:

- formation of ground-level fog

- ground-level icing

- salt deposition (if the cooling water is saline)

- noise

- visual effects of the plume and the cooling tower, aesthetically offensive to some people.

For the above effects that are caused by the condensation of the saturated air in a wet cooling tower exhaust, these impacts can be alleviated (if they are found to be significant) by use of a wet/dry combination tower where the exiting air is kept below saturation.

Various cooling towers have been investigated in detail by the Power Plant Siting Program, particularly in connection with the proposed Dickerson and Douglas Point Plants, to see what tradeoffs can be made with respect to the more important of the impacts listed above (20,21). An extensive measurement program has been carried out at the Chalk Point plant to study the effect on vegetation of salt drift from a brackish water cooling tower, as will be discussed subsequently.

Six different cooling tower designs were considered in the Douglas Point study. They were: (a) a natural draft tower; (b) a fan-assisted natural draft tower; (c) a full wet mechanical draft tower; (d) two wet/dry mechanical draft designs with varying degrees of wet-to-dry cooling ratios; and finally, (e) a round mechanical draft tower. The characteristics of each type of tower can be briefly described as follows:

- The natural draft tower is a big chimney, usually a hyperboloid (for mechanical reasons) where an updraft is created by the air being heated The air flow through the tower is entirely determined by ambient air temperature, relative humidity, and by the temperature of the cooling water. The air flow is highest at low ambient temperature, and decreases by almost 50 percent as the ambient temperature rises from the freezing point to the 90's.

- The fan-assisted natural draft tower uses fans around the base of the tower to stabilize the air flow through the tower so that it becomes almost independent of external conditions. Such a tower also has a slightly higher rate of evaporation at low temperatures, but approaches that of the natural draft tower at high temperatures. Its main advantage is its smaller size.

- The mechanical draft tower has its air flow completely controlled by fans and can be much smaller than natural draft towers, at the expense of additional power consumption.

- The wet/dry towers reduce evaporation, particularly in the winter (when the river flow may be low, and the decrease in water uptake may be important).

- The round mechanical draft tower is a special design where the fans are arranged in a centered configuration giving rise to enhanced updraft, thereby alleviating some of the environmental impacts of the low mechanical draft towers by dispersing the moist airborne plume more effectively.

Common to all evaporative cooling systems is the fact that the evaporated pure water leaves behind increasingly saline water. This concentrated water must be diluted or discharged (blow-down) from time to time (or continuously). This concentrated discharge may also carry residual biocides (such as chlorine) if not treated to neutralize them.

In addition, all cooling towers extract an energy penalty of 0.5 - 5.0% during temperature extremes due to increased condenser back-pressure. New types of turbines allow the maximum penalty to be shifted to either cold or warm weather, depending on the peak electrical demand of the utility and the inlet temperature of the cooling water.

The results of the Douglas Point study (20) are summarized in Table VI-2. The conclusions are that there is little ground fog induced for any of the tower designs considered; and that the natural draft tower is, as expected, the least susceptible to this effect. The wet/dry design offers little advantage over the all wet mechanical tower. The persistence of visible elevated plumes is highest for the natural draft tower, but long plumes (> 2 km) are not common. The salt drift deposition is appreciably smaller for the natural draft tower than for any other design, about a factor of 5 less than for the mechanical draft tower. Icing is not a significant factor for any of the configurations. Noise is the least from the natural draft tower, which also requires the least power for its operation. Natural draft towers may be aesthetically objectionable because of their great height. On balance, the natural draft tower appears to have the least impact on the physical and biological environment.

Chalk Point Cooling Tower Project

The cooling tower at the Chalk Point power plant (PEPCO) is the world's first large natural draft hyperbolic cooling tower to use brackish water. It began operation in 1975. Because the water in the cooling tower is brackish with the salinity ranging from 4 to 15 parts per thousand, the potential for damage to the terrestrial biota, accelerated corrosion, and the contamination of water bodies has been investigated. The Chalk Point Cooling Tower Project (CPCTP) of the State of Maryland Power Plant Siting Program has received the full cooperation of PEPCO and has been jointly supported by the U.S. Environmental Protection Agency, the U.S. Energy Research and Development Administration, the Electric Power Research Institute and the State of Maryland. This program, the first long-term, full-scale endeavor of its kind, has received world-wide attention.

CPCTP analyses and field programs (22) are being conducted to determine the extent of visible plumes, and the mechanisms of drift emissions and transport, as well as the impact of salt deposition on local vegetation and crops. Of particular interest is the effect on tobacco grown in the field surrounding Chalk Point, since it is known that chlorides can significantly effect burning qualities. A preliminary analysis of this data has been made, indicating that the cooling tower is not likely to produce off-site crop

Table VI-2. Comparison of cooling tower alternatives for the proposed Douglas Point power plant. The power plant consists of 2 generating units, each unit generating 1,100 MW with a condenser heat load of 16 x 10^9 BTU/hr (20).

Environmental Factors	Natural-Draft Tower	Fan-Assisted Natural-Draft Tower	Mechanical-Draft Tower			Round Tower
			Full-Wet	Wet-Dry Design 1	Wet-Dry Design 2	
Size	Height: 120-150 m Top Diameter: 55 m Bottom Diameter: 115 m	Height: 61 m Top Diameter: 49 m Bottom Diameter: 76 m	Each cell: height, 21 m length, 12 m width, 20 m	Each cell: height, 21 m length, 12 m width, 20 m	Each cell: height, 21 m length, 12 m width, 20 m	Height: 21 m Diameter: 75 m
Number of towers	One per generating unit	Two per generating unit [a]	~35 cells per generating unit [a]	~43 cells per generating unit [a]	~53 cells per generating unit	Two per generating unit
Ground-level fog induced off-site, hours per year	<4 at any particular off-site location	<10 at any particular off-site location	<25 at any particular off-site location	<22 at any particular off-site location	<21 at any particular off-site location	<5 at any particular off-site location
Elevated visible plume lengths: (annual average, percent of time exceeding indicated distance)	500 m (30%) 1,500 m (25%)	500 m (25%) 1,500 m (20%)	500 m (60%) 1,500 m (10%)	500 m (25%) 1,500 m (0%)	500 m (8%) 1,500 m (0%)	500 m (40%) 1,500 m (20%)
Salt drift deposition, pounds per acre per year	<42 at any particular off-site location, extreme conditions; <16 typical conditions	<91 at any particular off-site location, extreme conditions; <35 typical conditions	<226 at any particular off-site location, extreme conditions; <88 typical conditions, very high on-site	< Full-wet	<Design 1	<201 at any particular off-site location, extreme conditions; <78 typical conditions

Table VI-2. Comparison of cooling tower alternatives (Continued)

Environmental Factors	Natural-Draft Tower	Fan-Assisted Natural-Draft Tower	Mechanical-Draft Tower			Round Tower
			Full-Wet	Wet-Dry Design 1	Wet-Dry Design 2	
Near-term salt drift effects (b)	Off-site: none On-site: some corrosion and vegetation damage during periods of extreme river salinity	Off-site: limited effect on crops On-site: modest corrosion and damage to vegetation	Off-site: reduced crop yields On-Site: severe corrosion and damage to vegetation	Off-site: reduced crop yields On-site: severe corrosion and damage to vegetation	Off-site: reduced crop yields On-site: severe corrosion and damage to vegetation	Similar to fan-assisted natural-draft towers
Icing	None expected	None expected	Occasionally near tower	Less than full-wet	Less than Design 1	None expected
Noise from total plant complex	32.2 dB(A) at 5000 ft; this is 1.9 dB(A) increase over ambient noise level	Less than round mechanical-draft	36.3 dB(A) at 5000 ft; this is 5.9 dB (A) increase over ambient noise level	Slightly more than with full-wet tower	Slightly more than with Design 1 tower	Less than full-wet
Auxiliary power required for fans, MW per generating unit	None	≈8.2	≈5.3	≈6.5	≈8.0	≈8.2
Visual, aesthetic impact; ranking, 1 = most impact 6 = least impact	1	2	4	5	6	3

(a) Depends upon tower manufacturer and particular design.

(b) Long-term effects cannot be predicted.

damage. Peak depositions from the cooling tower fall within 1 km of the plant and effects beyond 1 mile will be small. At the point of maximum ground deposition, approximately 0.5 km (0.3 mi) from the cooling tower, the maximum monthly deposition is approximately 8 kg/ha (7 lb/acre). To date no evidence of salt damage has been observed to corn, soybeans, or tobacco grown on experimental field plots surrounding the site. In addition, experiments to determine the sensitivity of corn, soybeans, or tobacco to aerosol salt deposition indicate that no significant effects occur in the growing season at drift deposition rates up to 20 kg/ha/mo (18 lb/acre/mo). This far exceeds the drift deposition rates from the cooling tower at all off-site locations.

During the experimental program, it was discovered that the "wet" particulate scrubber associated with one of the generating units was also a major source of drift, which suggests that in all future siting on brackish water, it is important to consider the salt emissions from scrubbers when evaluating the environmental impact.

Future work in the program is directed towards improving the confidence in the predicted values of salt drift and evaluating the long-term effects of salt deposition.

Conclusions

The use of cooling towers is an environmentally acceptable alternative to "once-through" cooling systems. Basically, a cooling tower exchanges consumptive water use and possible terrestrial effects for effects in the aquatic environment. Because the balance of these effects is site-specific, each plant location should be examined to determine the appropriate cooling system.

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APPENDIX A

1978

TEN-YEAR PLAN OF MARYLAND ELECTRIC UTILITIES, POSSIBLE AND PROPOSED POWER PLANTS,

1978 through 1987

Public Service Commission
of Maryland
301 W. Preston Street
Baltimore, Maryland 21201

TABLE OF CONTENTS

I. INTRODUCTION

This report constitutes the 1978 Ten-Year Plan of the Public Service Commission of Maryland (referred to herein as the Commission or the PSC) regarding the possible and proposed sites, including associated transmission routes, for the construction of electric power plants within the State of Maryland. The report is in accordance with Section 54B (b) of Article 78 of the Annotated Code of Maryland. The plans herein are based upon the individual long-range plans submitted by the Maryland electric utilities, with supporting analyses and information by the Engineering Division of the Commission.

II. UTILITIES IDENTIFIED

The 16 retail electric companies presently operating in Maryland and subject to the jurisdiction of the Commission are listed in Attachment No. 1, according to type of ownership: investor-owned, municipally-owned, and customer-owned (i.e., cooperatives).

In addition, there are two non-retail electric companies owning generation property in Maryland. They are:

1. Pennsylvania Electric Company owns a hydro-electric plant on the Youghiogheny River, Garrett County (Deep Creek Lake Reservoir) and an associated transmission line.

2. Susquehanna Power Company, a wholly-owned subsidiary of Philadelphia Electric Company, owns the Conowingo hydro-electric plant on the Susquehanna River, Harford and Cecil Counties.

Of these 18 companies, only the 7 utilities listed below have future power plant siting interests in Maryland:

Baltimore Gas and Electric Company
Conowingo Power Company
Delmarva Power and Light Company of Maryland
Easton Utilities Commission
The Potomac Edison Company
Potomac Electric Power Company
Southern Maryland Electric Cooperative, Inc.

Of these 7 companies, two, namely, Conowingo Power Company and Southern Maryland Electric Cooperative, own no generation capacity at the present time.

III. 1978 TEN-YEAR SITING PLANS, BY COMPANY

General

These Plans reflect continued planning by the electric utilities for the deferral and stretch-out of new generation and associated transmission plant construction in the next decade. These current plans are indicative of the uncertainties in formulating long-range electric demand forecasts. A listing of the utility planned and possible new power plant sites is given in Attachment No. 7 (at end of report), arranged by utility and further indicating: name of site/plant, type of fuel, capacity, initial construction and in-service dates. A discussion and further explanation of the sites is given below:

1. Baltimore Gas and Electric Company

The second unit of the Calvert Cliffs nuclear plant became operational April 1, 1977. Total rated capacity of both units is 1730 MW.

In 1973 the Company was granted approval to begin construction of two 610-MW fossil-fueled steam units at Brandon Shores, Anne Arundel County. These two units are to become operational in 1981 and 1983, respectively. These dates represent a one-year stretch-out from last year's Plan.

New generating plant of 100-MW capacity is planned for Sollers Point, Baltimore County. Total acreage involved is 1000 acres. Actual size of the individual units, the kind of fuel and the year construction is to start are presently undetermined although completion is expected by 1986. This represents a two-year delay in completion date from the previous year's Plan. The Company had previously considered building a 200-MW plant at this site.

Additional generation is now being planned at the Safe Harbor Water Power Corporation hydro-electric plant. This plant is on the Susquehanna River, Lancaster County, Pennsylvania, approximately 20 miles upstream from the Maryland-Pennsylvania border.

The proposed expansion is being planned in conjunction with the application for the renewal in 1980 of the plant's operating license by the Federal Power Commission, filed April, 1977. If the license is not renewed, these expansion plans will be cancelled.

The expansion would include 5 units having a total capacity of 187.5 MW. Capacity entitlement of 125-MW would be allocated to the Baltimore Gas and Electric Company in the proportion of its ownership: 2/3 Baltimore Gas and Electric Company and 1/3 Pennsylvania Power and Light Company. No transmission line reinforcements will be required insofar as the Baltimore Gas and Electric Company is concerned.

The Company is considering the possibility of a 800-MW coal-fired plant to be located on an undetermined site in the northeastern section of Maryland. Approximately 800-1000 acres will be required. Cooling water, services and other special requirements are presently under review.

Last year's Company Plan listed a Northwest Substation in Baltimore County as the site of a peaking generating station. Plans for this station have been deleted. Plans for additional generation at the Perryman station, Harford County, have also been deleted.

2. Conowingo Power Company

The Philadelphia Electric Company and its wholly-owned subsidiary, Conowingo Power Company, operate their facilities as though these facilities were that of a single company. Conowingo customers thus obtain the benefits of being a part of the larger Philadelphia Electric system and of the PJM Interconnection, of which Philadelphia Electric is a member.

At the present time, almost all of the Philadelphia Electric system generation plant is in Pennsylvania. The Conowingo hydro-electric plant represents about 6% of the Philadelphia Electric's installed capacity.

An additional 938-MW of capacity is being added to the Philadelphia Electric system through the partial (42%) entitlement of the 220-MW nuclear generating plant at Salem, New Jersey. The first unit of this plant went on-line in June, 1977. The second unit is scheduled for service in 1979.

The Conowingo hydro-electric plant is a peaking generation station with an annual capacity factor of about 40%. Because of this, Conowingo is unable to supply just the Maryland load but instead must be operated in conjunction with base load generation plant of the Philadelphia Electric system.

A major new generating station in the Philadelphia Electric system is scheduled to become operational sometime within 1992-1994, with construction beginning approximately 1985. Prime location of this station is in Fulton Township, Lancaster County, Pennsylvania.

The three alternate locations for this station are in Maryland. They are the following sites:

Canal site
Bainbridge site
Seneca Point site

Conowingo Power Company presently owns 680 acres at the Canal site. This is located approximately 1 mile west of Chesapeake City, Maryland on the Chesapeake and Delaware Canal. The Canal site was listed in the application to the Nuclear Regulatory Commission for the Fulton Nuclear Generating Station, as an alternate site.

Bainbridge, formerly the location of the Naval Training Center just east of Port Deposit, Maryland, has approximately 1260 acres available for power plant construction. The State of Maryland is currently negotiating with the General Services Administration of the Federal Government for acquisition of this site, to be included with the Elms site in St. Mary's County, in the State Power Plant Site Bank. The Philadelphia Electric Company is interested in either joint or wholly-owned development of generation plant at this site.

The Seneca Point site is approximately 500 acres of which 394 are currently owned for future development. It is located on the west bank of the Northeast River, approximately 1 mile southwest of Charlestown, Cecil County, Maryland.

At any of these three sites, development would probably be two base load nuclear-fueled units for possible service in the 1990's. Unit capacity would be in the 1100-1500-MW range. Alternately, the development could be equivalent fossil-fueled capacity. Final determination of the type of plant would depend on detailed studies including plant and fuel costs, environmental considerations and licensing aspects.

3. Delmarva Power and Light Company of Maryland

The Company has no proposed generating station sites either through ownership or under option. Studies are continuing on potential plant sites in the lower eight Maryland counties on the eastern shore. No information is available on specific sites at this time.

4. Easton Utilities Commission

In 1975, the Public Service Commission granted Easton Utilities Commission a Certificate of Public Convenience and Necessity for the construction of a new generating plant, known as Plant No. 2. Located on a Town-owned 7-acre site within the city limits of Easton, this plant is presently under construction, with completion of the first two units, having a total capacity of 12.5-MW, now scheduled for 1978. This was to be completed in 1977, according to the Easton Utilities Commission's 1977 Plan.

Additional capacity will be incorporated at Plant No. 2 in 1982 and 1986. Prime mover of all units will be diesel engines, fueled by No. 2 fuel oil.

5. <u>The Potomac Edison Company</u>

The Company owns one site in Maryland for possible use as a power generation site. This site, known as Point of Rocks, is in Frederick County, 2¼ miles down the Potomac River from the community of Point of Rocks.

This site, containing 829 acres, was purchased for a nuclear generating facility having an ultimate capacity of about 2500-MW. There are no active plans at the present time to proceed with construction at this site.

After extensive internal study and discussions with the state power plant siting program, the Company has withdrawn the Black Oaks site in Allegany County from consideration as a location of a future generation plant.

The Black Oak site has three serious deficiencies for power generation: air quality, flooding and water makeup. The problem of meeting applicable governmental air quality standards appears to be insoluble.

The Company has no plans for expansion of its R. Paul Smith plant at Williamsport or its Celanese power plant, the only existing plants it operates in Maryland.

6. <u>The Potomac Electric Power Company</u>

On June 9, 1977 the Company announced the indefinite deferral of its plans to construct a nuclear generating station at Douglas Point in Charles County. However, the site will be retained for eventual construction of a generation plant when the needs so warrant. NRC (Nuclear Regulatory Commission) site suitability determination will be pursued. Specific contracts and arrangements associated with the two planned units will be abandoned, sold, terminated or otherwise dealt with, as determined by economic analysis and estimates of future technical applicability.

Potomac Electric Power Company now expects the 600-MW Unit No. 4 at Chalk Point to begin commercial service in 1982. It is now under construction. This represents a 2 year delay from the 1980 date given in the Company plans last year.

This unit will burn residual fuel oil in accordance with the Carter Administration policy of allowing existing plants to burn oil where coal-firing capability does not exist.

In June, 1977, PEPCO and Baltimore Gas and Electric Company executed an Agreement in Principle on the Dickerson #4 coal-fired unit. This agreement calls for tenancy in common with equal shares of ownership. Capacity and KWH output will be shared equally with the Baltimore Gas and Electric Company. PEPCO is designated as the managing party, to serve as agent for construction and operation of this Unit.

Construction of the 800-MW Dickerson Unit No. 4 is to begin in 1978 with commercial service expected in 1985. This represents a 3-year stretch-out in the operational date.

According to PEPCO, requirements still exist for a 1000-MW pumped-storage hydro-electric plant to be located on a 1000 acre undetermined site in Maryland. The year this site is needed to become operational is not specified.

7. Southern Maryland Electric Cooperative, Inc.

The Cooperative owns a 300 acre site on the Patuxent River, St. Mary's County. This site, known as the Della Brooke Farm, is considered for possible future generation. However, no plans have been made for such use.

IV. PROJECTED GROWTH IN PEAK LOAD AND GENERATING CAPACITY

The growth in peak load and in installed generation capacity within Maryland, as projected by each utility (except The Potomac Edison Company) over the next decade, 1978-1987, is listed in Attachment 2. The listing of the utilities is by regional areas in the State. This arrangement allows demand and generating capacity by region to be readily compared. The numbers within parenthesis are changes from the projections made last year.

A third potline at the Eastalco plant in Frederick County is under consideration. Depending upon approval of appropriate environmental permits, this line is estimated to become operation during the winter of 1979/1980. At this time, this load will increase the peak demand by 35-MW and by 130-MW for each year thereafter. Formal notice of this additional load, however, has not been received by The Potomac Edison Company.

Attachment #2A lists the projections in the Maryland peak load, both with and without this third ptoline, for The Potomac Edison Company over the next ten-year period, 1978-1987. The Company's generating capacity in this period will remain at 139-MW.

The Potomac Electric Power Company data in Attachment No. 2 are for the entire Company system. PEPCO's service area includes the entire District of Columbia, the Pentagon and Rosslyn complexes in Virginia, as well as the Metropolitan Washington area lying in Maryland. PEPCO owns generation plants in the District, Virginia and Maryland, and shares with other utilities mine-mouth generating plants in Pennsylvania.

Data on the Baltimore Gas and Electric Company generation include a proportionate share of the Keystone and Conemaugh Mine-Mouth plants in Pennsylvania.

The generating facilities of the Hagerstown Municipal Plant have a total nameplate rating of 20-MW capacity. These facilities are maintained on a stand-by basis and are used for peaking purposes only when The Potomac Edison Company is unable to supply the demand. Present interconnection capability with The Potomac Edison Company is 65-MW.

Also listed on Attachment No. 2 are estimates of the average annual growth rate of both the peak load and generating capacity for each utility and for the state as a whole. These rates are computed as compound rates over the ten-year period, 1978-1987. The corresponding doubling times are also listed.

The individual peak loads do not sum to the listed state totals in Attachment No. 2. Peak demand data for Hagerstown and Southern Maryland are excluded from the state figures since these data for these utilities are included in The Potomac Edison Company and Potomac Electric Power Company figures, respectively.

Attachment No. 3 is a summary of the projected annual growth rates in peak demand and installed generating as predicted by the utilities in their 1976, 1977 and 1978 (current) Ten-Year Plans. State-wide data are also shown.

Several observations concerning these estimates should be noted:

1. This year the community of Easton projects the highest growth in peak demand (8.4% per year) in the state.

2. In the estimate made last year Southern Maryland Coop. expected an annual growth in demand of 10.5%. This has now been scaled down to a more modest 6.1%, still significantly higher than the state as a whole

3. Lowest growth in peak demand in the state is again projected for the PEPCO service area (3.1%), down from the 4.0% estimate in the 1977 Plan.

4. Baltimore, the other major metropolitan area, is expecting a growth of 5.2%, down slightly from the 1977 estimate of 5.4%.

5. The Potomac Edison Company, which serves virtually all of western Maryland, estimates its growth in peak demand at 5.7% without the additional pot-line in the Eastalco plant, virtually unchanged from the 1977 figure. With this pot-line, the estimate is 7.2%. The load created by this additional pot-line is almost 11% of the peak load expected during the winter of 1980-1981, when it may become on-line.

6. For the state as a whole, peak demand is expected to increase at 4.5% per year average. This is down from the 5.1% estimate last year.

Attachment No. 4 is a bar graph of these expected annual growth rates for these 5 principal regions and for the state.

V. COMPARISON OF 1978 and 1977 BG&E AND PEPCO TEN-YEAR PLANS

Shown on Attachment No. 5 are the ten-year projections of the peak demand, installed generating capacity and reserve margin for the Baltimore Gas and Electric Company and Potomac Electric Power Company as given in their 1977 and 1978 Plans. Differences between these estimates are also listed for comparison purposes.

The reserve margin is usually defined by the relation:

$$\text{Reserve Margin} = \frac{\text{Installed Generating Capacity - Peak Load}}{\text{Peak Load}} \times 100$$

This definition is used in this Plan.

Current Potomac Electric Power Company reserve margin estimates for the next ten years varies from a minimum of about 17.4% in 1981 to a peak of 29.0% next year. The average margin over this decade is 22.1%, down somewhat from the 24.8% average in last year's estimate.

For the Baltimore Gas and Electric Company the estimated reserve margin peaks at 28.4% next year with a low of about 14.5% for the years 1980, 1982, 1984 and 1986. The current estimate of the margin over the next decade is 15.7% which is also less than the estimate for this same period in last year's plan (22.9%).

Attachment No. 6 graphs the estimated reserve margins for these two utilities.

VI. POWER PLANT CONSTRUCTION SCHEDULES

Attachment No. 7 has been prepared to assist in visualizing the planning schedules for new electric generation facilities in Maryland. Dashed lines and dashed blocks show indefinite construction and/or in-service dates of proposed new generation.

VII. ASSOCIATED TRANSMISSION LINES

The transmission lines associated with the construction of new generating stations will generally operate at 115KV and higher voltages. They will require rights-of-way widths of 150 to 300 feet. An "associated transmission line", with respect to Section 54B of Article 78, refers to the means of transporting electric power from a power plant to one or more points on an existing transmission system. Such lines are often called "generation leads". There are also "transmission lines", with respect to Section 54A of Article 78, which are not "generation leads" but rather they provide substation-to-substation bulk power transmission for increased capacity or reliability purposes. In any of these instances, the long-range need and probable capacity of a future transmission line can be determined from extensive system studies. However, the actual route and often the actual terminal location/s of a line can be established only after subsequent years of planning and surveys.

Lines planned for possible construction at later dates and in particular the "associated transmission lines" for new power plants cannot be defined as to specific siting. However, general planning information regarding terminal points, voltage levels and dates to the extent possible is contained in the individual plans submitted by the major companies.

VIII. FURTHER INQUIRY

In the event further inquiry is indicated, such as by other state agencies, the request may be directed to the Commission by writing to Mr. Frank J. Wasowicz, Executive Secretary. Specific information requests of an engineering nature and comments on this Plan may be directed to Mr. John W. Dorsey, Chief Engineer.

ATTACHMENT NO. 1

RETAIL ELECTRIC COMPANIES OPERATING IN MARYLAND

NAME	ADDRESS	TELEPHONE NO.
Investor Owned		
Baltimore Gas and Electric Company	Gas and Electric Building Baltimore, MD 21203	234-5000
Conowingo Power Company	211 North Street Elkton, MD 21921	1-398-1400
Delmarva Power and Light Company of Maryland	P. O. Box 1739 Salisbury, MD 21801	1-749-6111
Potomac Edison Company, The	Downsville Pike Hagerstown, MD 21740	1-731-3400
Potomac Electric Power Company	1900 Pennsylvania Avenue., N. W. Washington, D. C. 20006	1-202-872-2449
Municipally Owned		
Berlin, Mayor and Council of	P. O. Box 235 Berlin, MD 21811	1-641-2770
Centreville, The Town of	Centreville, MD 21617	1-758-0830
Easton Utilities Commission, The	11 S. Harrison Street Easton, MD 21601	1-822-6110
Hagerstown Municipal Electric Light Plant	Hagerstown, MD 21740	1-731-2600
St. Michaels Utilities Commission	St. Michaels, MD 21663	1-745-9400
Thurmont Municipal Light Company	P. O. Box 385 Thurmont, MD 21788	1-271-7313
Williamsport, Mayor & Council of	Williamsport, MD 21795	1-223-7711
Customer Owned		
A and N Electric Cooperative	Parksley, Virginia 23421	1-804-665-5116
Choptank Electric Coop., Inc.	P. O. Box 430 Denton, MD 21629	1-479-0380
Somerset Rural Electric Coop., Inc.	P. O. Box 270 125 E. Fairview Street Somerset, PA 15501	1-814-445-4106
Southern Maryland Electric Coop., Inc.	Hughesville, MD 20637	1-274-3111

ATTACHMENT NO. 2

PROJECTED TEN-YEAR GROWTH IN PEAK ELECTRIC
DEMAND AND IN INSTALLED GENERATING CAPACITY IN MARYLAND
1978-1987 TIME PERIOD
IN MEGAWATTS

REGION	1978		1979		1980		1981	
	PEAK LOAD	GEN. CAP.	PEAK LOAD	GEN. CAP.	PEAK LOAD	GEN. CAP.	PEAK LOAD	GEN. CAP.
Balto. Metro								
BG&E (1)	4020 (2) (-110) (3)	5162(-120)	4280(-110)	5162(-120)	4510(-120)	5162(-730)	4750(-130)	5772(-120)
Washington Metro								
PEPCO (5) (Entire System)	3885(-266)	5013(+3)	4017(-346)	5013(+3)	4142(-409)	5013(-597)	4269(-488)	5013(-597)
Western Maryland								
Hagerstown (6)	51	20	54	20	58	20	61	20
Potomac Edison	(4)	139	(4)	139	(4)	139	(4)	139
Southern Maryland								
South. MD Elec. Coop., Inc.	242(+10)	0	259(+2)	0	279(+7)	0	293(-25)	0
Eastern Shore								
A & N (6)	1	1	1	1	1	1	2	1
Berlin (6)	N/A	4	N/A	4	N/A	4	N/A	4
Conowingo	86	0	90	0	94	0	98	0
Delmarva	390(-19)	258(0)	410(-38)	258(0)	435(-56)	258(0)	460(-70)	258(0)
Easton	26.3(-0.3)	44.6(0)	28.5(-0.3)	44.6(0)	30.9(-0.2)	44.6(0)	33.4(-0.3)	44.0(0)
State Totals 8								
W/O P/L 8	9416(-396) (7)	10642(-117)	9899(-494)	10642(-117)	10348(-586)	10642(-1327)	10806(-689)	11250(-718)
W P/L	9416(-396) (7)		9899(-494)		10383(-551)		10936(-559)	

NOTES:
(1) Generation in Pennsylvania included
(2) Baltimore Group Load
(3) Numbers in parentheses indicates changes from 1977 Plan
(4) Load data are shown on Attachment No. 2A
(5) Includes all customers including Sales For Resale
(6) Data from 1976 Plan
(7) Non-coincident peak load totals
(8) Eastalco 3rd pot line

ATTACHMENT NO. 2, continued

UTILITY	1982		1983		1984		1985	
	PEAK LOAD	GEN. CAP.	PEAK LOAD	GEN. CAP.	PEAK LOAD	GEN. CAP.	PEAK LOAD	GEN. CAP.
B G & E	5000(-130)	5721(-730)	5260(-140)	6331(-120)	5530(-140)	6331(-320)	5800(-140)	6731(-220)
PEPCO	4453(-536)	5613(-797)	4594(-551)	5613(-797)	4749(-552)	5613(-797)	4866(-590)	6013(-1575)
Hagerstown	65	20	69	20	73	20	74	20
Potomac Edison	4	139	4	139	4	139	4	139
South. MD Elec. Coop., Inc.	310(-40)	0	329(-59)	0	343(-87)	0	366(-109)	0
A & N	2	1	2	1	2	1	2	1
Berlin	N/A	4	N/A	4	N/A	4	N/A	4
Conowingo	103	0	107	0	112	0	117	0
Delmarva	490(-82)	258(0)	515(-102)	258(0)	545(-121)	258(0)	575(-144)	258(0)
Easton	36.2(-0.2)	56.5(0)	39.3(-0.1)	56.5(0)	42.6(0)	56.0(0)	46.1(0)	56.0(0)
State Totals W/O P/L	11340(-747)	11674(-1665)	11817(-793)	12283(-1056)	12363(-813)	12283(-1256)	12869(-874)	13083(-1934)
W P/L	11470(-617)		11947(-663)		12493(-683)		12999(-744)	

ATTACHMENT NO. 2, concluded

UTILITY	1986 PEAK LOAD	1986 GEN. CAP.	1987 PEAK LOAD	1987 GEN. CAP.	AVERAGE OVERALL GROWTH %/Yr. PEAK LOAD	AVERAGE OVERALL GROWTH %/Yr. GEN. CAP.	DOUBLING TIME YEARS PEAK LOAD	DOUBLING TIME YEARS GEN. CAP.
B G & E	6080(-150)	6956(-1195)	6370	7698	5.2	4.5	13.6	15.6
PEPCO	4983(-703)	6013(-1575)	5103	6013	3.1	2.0	22.9	34.3
Hagerstown	N/A	N/A	N/A	N/A				
Potomac Edison	4	139	4	139	4	0	4	-
South. MD Elec. Coop., Inc.	390(-125)	0	413	0	6.1	-	11.7	-
A & N	2	1	2	1	8.0	0	9.0	-
Berlin	N/A	4	N/A	4	N/A	0	-	-
Conowingo	122	0	128	0	4.5	-	15.7	-
Delmarva	605(-171)	258(0)	635	258	5.6	0	12.8	-
Easton	50.0(+0.2)	81.0(0)	54.2	80.4	8.4	6.8	8.6	10.6
State Totals								
W/O P/L	13332(-1091)	12676(-3546)	13888	14054	4.4	3.1	16.1	22.4
W P/L	13462(-961)		14018		4.5		15.7	

ATTACHMENT NO. 2A

PROJECTED TEN-YEAR GROWTH IN PEAK ELECTRIC
DEMAND AND IN INSTALLED GENERATING CAPACITY IN MARYLAND
1978-1987 PERIOD
MEGAWATTS

THE POTOMAC EDISON COMPANY

	Winter 1977/78		Winter 1978/79		Winter 1979/80		Winter 1980/81	
	PEAK LOAD	GEN. CAP.	PEAK LOAD	GEN. CAP.	PEAK LOAD	GEN. CAP.	PEAK LOAD	GEN. CAP.
Without 3rd Potline, Eastalco, Frederick Co.	1008(0)	139	1072(0)	139	1136(0)	139	1194(0)	139
With 3rd Potline, Eastalco, Frederick Co.	1008(0)	139	1072(0)	139	1171(+35)	139	1324(+130)	139
	Winter 1981/82		Winter 1982/83		Winter 1983/84		Winter 1984/85	
	1256(0)	139	1300(0)	139	1382(0)	139	1463(0)	139
	1386(+130)	139	1430(+130)	139	1512(+130)	139	1593(+130)	139
	Winter 1985/86		Winter 1986/87		Average Overall Growth %/Yr.		Doubling Time Years	
	1554(0)	139	1663	139	5.7	0	12.5	-
	1684(+130)	139	1793	139	7.2	0	10.0	-

Notes: Includes all customers in Maryland, including 3 Sales for Resale customers, Hagerstown, Thurmont and Williamsport
Numbers in parenthesis indicate changes from 1977 Ten-Year Plan figures

ATTACHMENT NO. 3

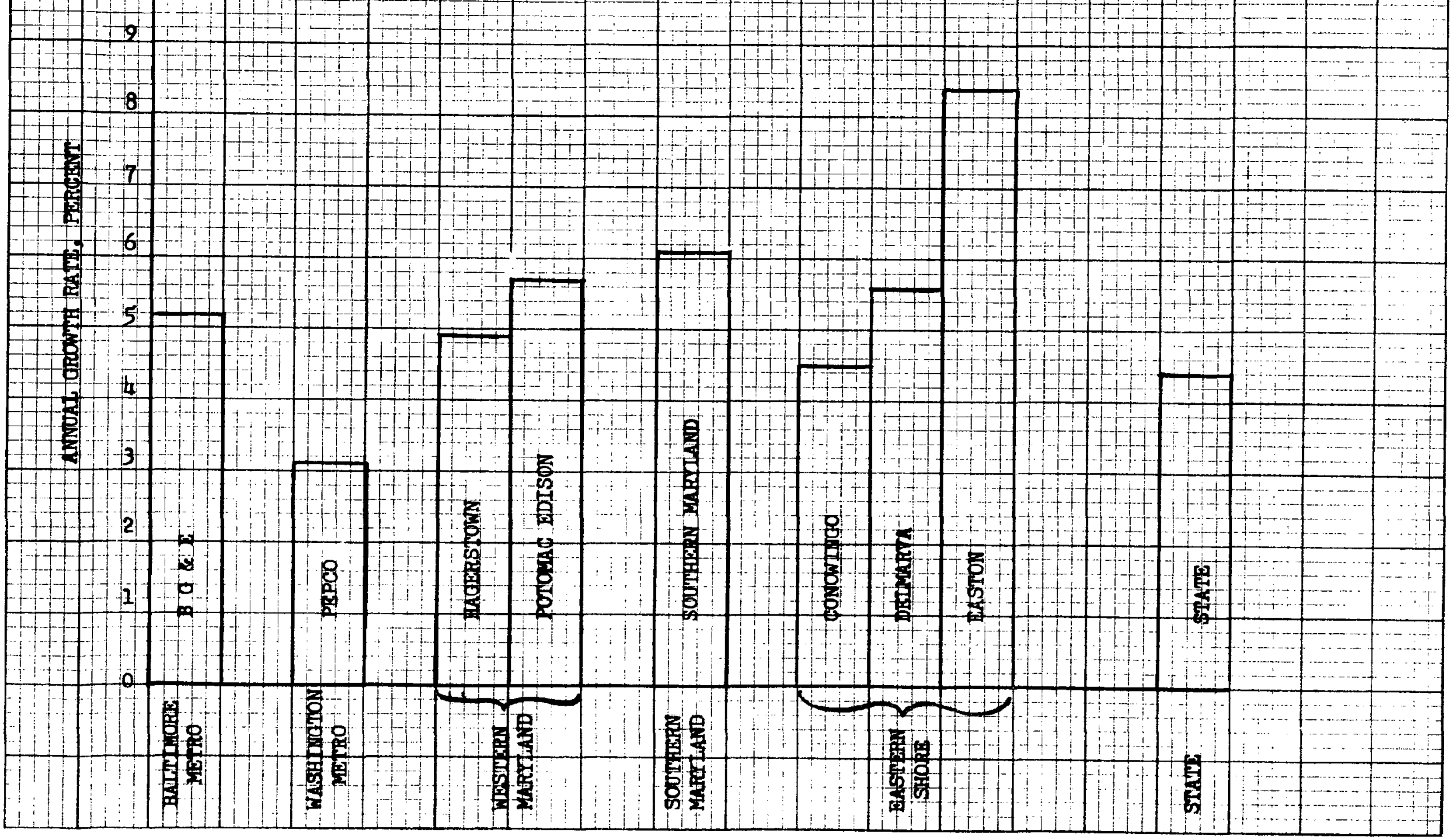
COMPARISON OF PROJECTED ANNUAL GROWTH RATES
IN PEAK DEMAND AND INSTALLED GENERATING CAPACITY
AS PRESENTED IN THE
1976, 1977 AND 1978 TEN-YEAR PLANS
PERCENT PER YEAR

	1976 TEN-YEAR PLAN (1976-1985)		1977 TEN-YEAR PLAN (1977-1986)		1978 TEN-YEAR PLAN (1978-1987)	
	Peak Load	Gen. Cap.	Peak Load	Gen. Cap.	Peak Load	Gen. Cap.
REGION						
Baltimore Metro						
B G & E	6.0	7.3	5.4	5.0	5.2	4.5
Washington Metro						
PEPCO	4.2	4.7	4.0	4.7	3.1	2.0
Western Maryland						
Hagerstown	4.9	0	4.9	0	4.9	0
Potomac Edison	5.8	(-3.6)	5.6	0	5.7 ① 7.2 ②	0
Southern Maryland						
Southern Maryland	10.7	-	10.5	-	6.1	-
Eastern Shore						
Conowingo	7.0	-	4.5	-	4.5	-
Delmarva	6.8	0	8.4	0	5.6	0
Easton	9.7	6.2	8.2	6.9	8.4	6.8
Entire State						
Percentage	5.3	5.8	5.1	4.7	4.4 ① 4.5 ②	3.1
Years to Double	13.4	12.4	14.0	15.1	16.1 ① 15.7 ②	22.4

Notes: ① Without 3rd Potline installed at Eastalco, Frederick County
② With 3rd Potline installed at Eastalco, Frederick County

ATTACHMENT NO. 4

PROJECTED ANNUAL GROWTH RATES
IN PEAK DEMAND
1978 - 1987 PERIOD



ATTACHMENT NO. 5

TEN-YEAR PROJECTIONS OF PEAK ELECTRIC DEMAND, INSTALLED CAPACITY, AND RESERVE MARGIN, 1977 and 1978 TEN-YEAR PLANS OF BALTIMORE GAS AND ELECTRIC COMPANY AND POTOMAC ELECTRIC POWER COMPANY

	1978			1979			1980			1981		
	Peak Load MW	Gen. Cap. MW	Res. Margin %	Peak Load MW	Gen. Cap. MW	Res. Margin %	Peak Load MW	Gen. Cap. MW	Res. Margin %	Peak Load MW	Gen. Cap. MW	Res. Margin %
Baltimore Gas & Electric												
1978 Plan	4020	5162	28.4	4280	5162	20.6	4510	5162	14.5	4750	5772	21.5
1977 Plan	4130	5282	27.9	4390	5282	20.3	4630	5892	27.3	4880	5892	20.7
Difference	-110	-120	0.5	-110	-120	0.3	-120	-730	-12.8	-130	-120	0.8
Potomac Electric Power Company(1)												
1978 Plan	3885	5013	29.0	4017	5013	24.8	4142	5013	21.0	4269	5013	17.4
1977 Plan	4151	5010	20.7	4363	5010	14.8	4551	5610	23.3	4757	5610	17.9
Difference	-266	3	8.3	-346	3	10.0	-409	-597	-2.3	-488	-591	-0.5

(1) Entire System

ATTACHMENT NO. 5, continued

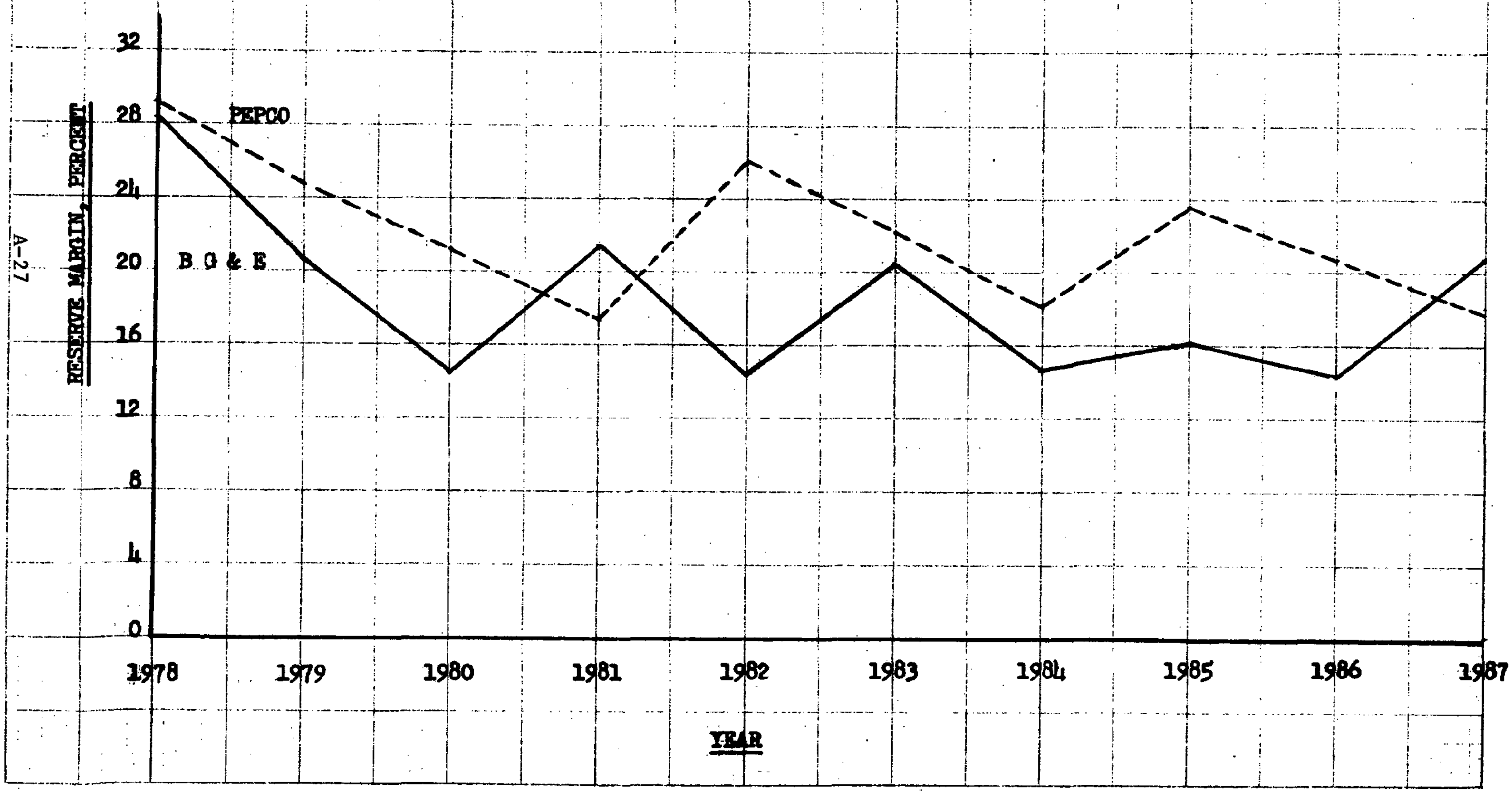
	1982			1983			1984		
	Peak Load MW	Gen. Cap. MW	Res. Margin %	Peak Load MW	Gen. Cap. MW	Res. Margin %	Peak Load MW	Gen. Cap. MW	Res. Margin %
Baltimore Gas & Electric									
1978 Plan	5000	5721	14.4	5260	6331	20.4	5530	6331	14.5
1977 Plan	5130	6451	25.7	5400	6451	19.5	5670	6651	17.3
Difference	-130	-730	-11.3	-140	-120	0.9	-140	-320	-2.8
Potomac Electric Power Company									
1978 Plan	4453	5613	26.0	4594	5613	22.2	4749	5613	18.2
1977 Plan	4989	6410	28.5	5145	6410	24.6	5301	6410	20.9
Difference	-536	-797	-2.5	-551	-797	-2.4	-552	-797	-2.7

ATTACHMENT NO. 5, concluded

	1985			1986			1987		
	Peak Load MW	Gen. Cap. MW	Res. Margin %	Peak Load MW	Gen. Cap. MW	Res. Margin %	Peak Load MW	Gen. Cap. MW	Res. Margin %
Baltimore Gas & Electric									
1978 Plan	5800	6731	16.1	6080	6956	14.4	6370	7698	20.8
1977 Plan	5940	6951	17.0	6230	8151	30.8	-	-	-
Difference	-140	-220	-0.9	-150	-1195	-16.4	-	-	-
Potomac Electric Power Company									
1978 Plan	4866	6013	23.6	4983	6013	20.7	5103	6013	17.8
1977 Plan	5456	7588	39.1	5691	7588	33.3	-	-	-
Difference	-590	-1575	-15.5	-708	-1575	-12.6	-	-	-

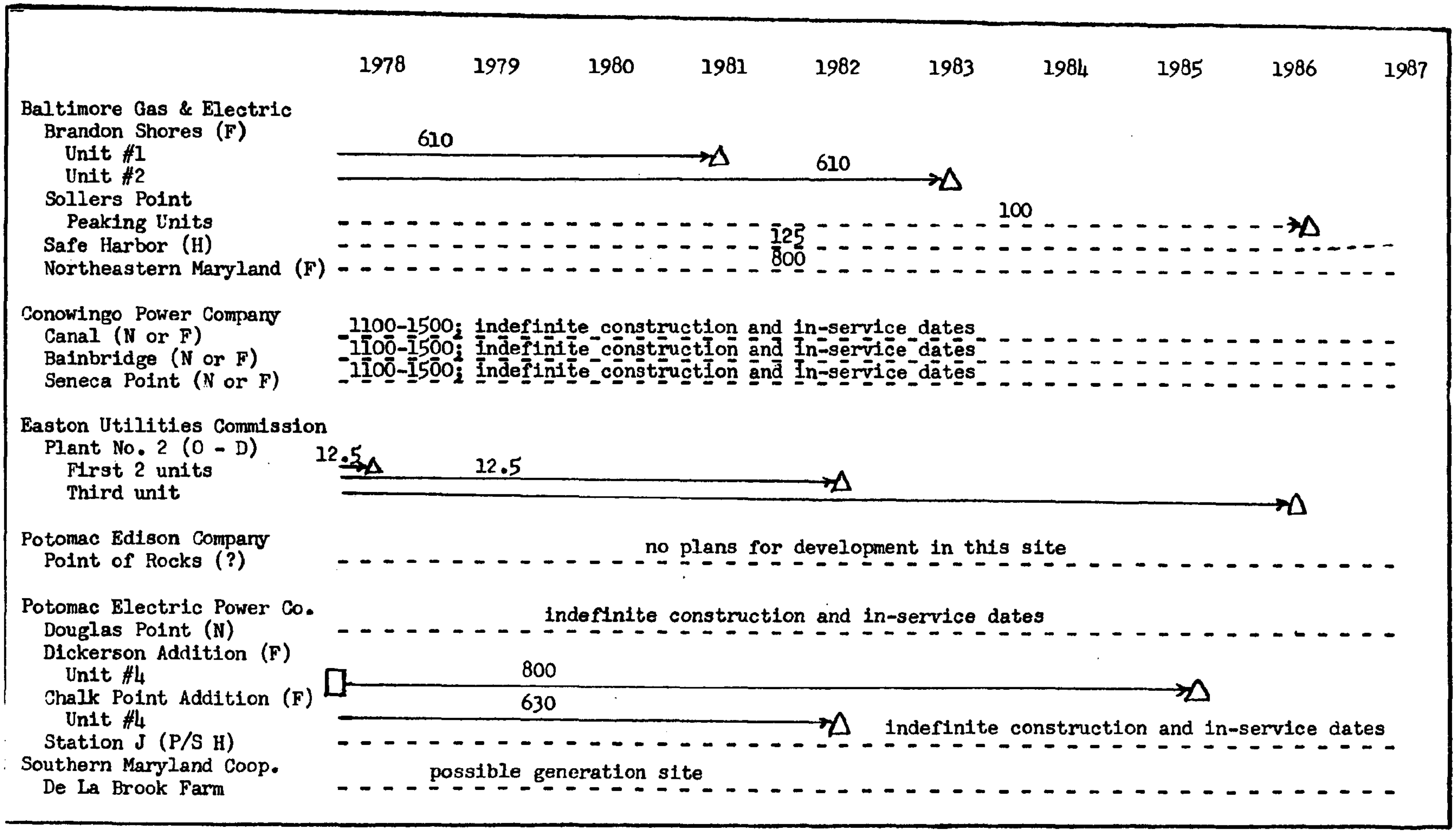
ATTACHMENT NO. 6

ESTIMATED RESERVE MARGIN (INSTALLED)
B G & E and PEPCO
Percent



ATTACHMENT NO. 7

TIME SCHEDULE FOR IMPLEMENTING
NEW ELECTRIC GENERATING PLANTS IN MARYLAND,
1978 - 1987 Period



ATTACHMENT NO. 7, concluded

KEY

□ - Date of Initial Construction

△ - In-Service Dates

(N) - Nuclear-Fueled

(F) - Fossil-Fueled

(O - D) - Oil-Fired Diesel

(P/S H) - Pumped Storage Hydroelectric

(?) - Type of Fuel Undecided

Numbers on horizontal lines denote planned capacity in megawatts.

APPENDIX B

ELECTRICITY CONSUMPTION IN MARYLAND

THE NEXT TEN YEARS

Prepared by

The Electrical Energy Forecasting Unit,
Division of Planning Research Programs,
Maryland Department of State Planning

INTRODUCTION

Over the years, the demand for electricity in the State of Maryland has remained generally consistent with national trends, and this consistency is anticipated for the future. In the decade preceding the 1973 oil embargo, rising incomes, gererally steady electricity prices, industrial expansion, and a growing population caused rapid growth in Maryland's consumption of electric energy. As Table B-1 indicates, the State experienced a growth rate even higher than that of the nation as a whole. Between 1962 and 1973 national consumption rose 8.5% in the residential sector and 6.9% in the nonresidential sector, while the State of Maryland recorded growth rates of 10.39% and 9.29% respectively in these two sectors.

This steady and rapid exponential growth was ended in 1974 by sharp energy price increases and the deep recession which followed. Both national and State electrical energy consumption figures exhibit virtually no growth between 1973 and 1975. The impact of these events upon energy usage was greater in Maryland than for the rest of the nation. Since 1975, State and national consumption has again resumed growth, largely due to the expansion of the economy and the moderation of the rates of increase in electricity prices. Despite the resumption in the growth of demand, however, it is not generally expanding at rates approaching the pre-1973 era, and as Table B-2 clearly indicates, forecasters at both the national and State level expect the rate of future expansion to be far below that of the 1960's. In fact, expansion over the next ten years is expected to proceed at rates slightly lower than those over the last two years, since the 1975-1977 growth rate reflects the extraordinarily depressed base figure recorded for 1975.

Electric energy is normally measured in kilowatt hours. One kilowatt hour (kWh) is the amount of electricity required to power a 100 watt light bulb for ten hours. This is the unit in which electricity is normally sold to consumers. It is also common for utilities to express total sales in megawatt-hour units (MWh), where one megawatt-hour equals 1,000 kilowatt hours.

Although an annual kilowatt-hour forecast indicates a community's future energy needs, a planner is also interested in "demand" -- the amount of power being drawn from a system by electricity consumers at any given instant in time. Peak demand refers to the maximum level of demand on a utility system within a specified time period (for example, a year). It is commonly measured in kilowatts (kW) or megawatts (MW). Peak demand is an important concept because it indicates the total electricity generating capacity required to service the needs of electric power customers.

The following pages briefly examine the basic factors which govern energy consumption, and which determine the methods and accuracy of forecasting energy demand in the State.

Table B-1. Electric energy sales in Maryland and the US

Year	U.S. (Billions of kWh)		Maryland (Millions of kWh)	
	Residential	Non-Residential	Residential	Non-Residential
1962	226.4	549.7	3,145	6,879
1963	241.7	589.9	3,425	7,491
1964	262.0	628.3	3,789	8,307
1965	281.0	672.4	4,229	9,081
1966	306.6	732.4	4,792	10,220
1967	331.5	775.5	5,196	11,209
1968	367.7	834.6	5,990	12,268
1969	407.9	899.3	6,700	13,497
1970	447.8	943.6	7,483	15,004
1971	479.1	987.4	7,919	16,311
1972	511.4	1,066.3	8,406	17,005
1973	554.2	1,149.0	9,330	18,270
1974	555.0	1,145.8	9,200	17,910
1975	586.1	1,146.9	9,598	17,859
1976	613.1	1,236.6	10,064	19,837*
1977	652.3	1,298.5	10,718	20,935
		Average Annual Compound Growth Rates		
1962-73	8.5%	6.9%	10.39	9.29
1973-75	2.8%	- .1%	1.43	-1.13
1975-77	5.8%	6.2%	5.67	8.27*

* Service to the Eastalco aluminum plant was initiated in 1976.

Sources: CEIR 1975 Table 2.1; Electric World (3/15/78 and 3/15/73); Annual Reports of the Electric Utilities in Maryland, Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry 1976

Table B-2. National and Maryland projected electric energy consumption and peak demand (consumption in billions of kilowatt hours and peak demands in millions of kilowatts)

	National				State			
Year	Residential	Non-Residential	Total	Peak Demand	Residential	Non-Residential	Total	Peak Demand
1977*	656.5	1,292.7	1,949.2	398.2	10.718	20.935	31.653	9.438
1980	764.3	1,473.1	2,237.4	474.9	11.990	24.858	36.847	10.186
1985	958.8	1,873.7	2,832.5	621.3	15.626	31.542	47.168	12.179
1987	1,039.0	2,066.4	3,105.4	688.3	16.393	34.495	50.888	13.098
				Average Annual Compound Growth Rates				
1977-80	5.20	4.45	4.70	6.05	3.81	5.89	5.20	2.57
1980-85	4.64	4.93	4.83	5.52	5.44	4.88	5.06	3.64
1985-87	4.10	5.02	4.71	5.25	2.42	4.58	3.87	3.70
1977-87	4.70	4.80	4.77	5.63	4.34	5.12	4.86	3.33

*National peak demand for 1977 is estimated, and all other 1977 figures are actual

Sources: For Maryland, the PEPCO and BG&E portions are Maryland Department of State Planning forecasts, and the remainder are company projections

DETERMINING ELECTRICITY USAGE

During the pre-embargo years, utility planners and forecasters for Maryland and the nation could expect energy sales to increase at a predictable, steady rate. This is no longer the case, and forecasting has become far more difficult and complex than in the past. At the same time, accurate demand projections have never been more important. Failure to anticipate and plan for increased demand may result in disruptions of service to customers, in undue cost increases if there is a shortage of total generation capacity, or in inefficient mix of generating plants. On the other hand, overestimating future demand risks imposing an unnecessary burden on the community for supporting the additional cost of idle generating capacity that has been constructed too far ahead of demand. In this context, it is necessary to focus sharply on the underlying determinants of both past and future consumption.

As mentioned previously, it is no longer reasonable to believe that electric energy consumption will continue to grow as rapidly or steadily as in the pre-embargo past. The nation's experience from 1973 to 1975 serves as convincing evidence that consumption patterns are highly sensitive to such factors as electricity price and income. As Table B-3 illustrates, a considerable rise in electricity price has occurred in Maryland since 1973. Moreover, the bulk of this price increase took place between 1972 and 1975, with only moderate increases in price in the following two years. Correspondingly, we observe stagnant demand over the 1973-1975 period and moderate recovery thereafter. This pattern, of course, cannot be attributed solely to price changes; it is also a function of the general behavior of the U.S. economy.

Residential consumption of electricity is based largely upon housing characteristics (e.g., percentage of apartment units), and the extent of the use of electric appliances, which, in turn, is likely to be dependent upon household income, the price of electricity, and, for certain appliances, the price of alternative fuels (e.g., consumers decide on the basis of relative fuel prices between gas and electric heating). Recently, the availability of natural gas, as well as its price, has become a significant influence.

For a given stock of electrical appliances, electricity prices and weather conditions will determine the extent to which the stock is utilized, and changes in these factors will determine the short run changes in the residential use of electricity. For example, an increase in electricity price will induce consumers to run airconditioners less frequently. Finally, it may be assumed that a "conservation ethic," distinct from high energy prices, may also influence residential consumption.

Energy consumption in the nonresidential sector is obviously closely related to the total output of the economy, and consequently does not exhibit rapid growth during slowdowns in overall economic activity. In addition, the nonresidential sector is extremely heterogenous, consisting of such diverse subsectors as government, farming, manufacturing, trade, and services, some of which are greater energy users than others. Thus, as shares of output shift among these subsectors, electricity consumption growth is correspondingly

Table B-3. Typical monthly electric bills 1972, 1974, 1977 (current year dollars)

Company	1972	1975	1977	% Change 1972-1975	% Change 1975-1977
BG&E					
Residential	15.30	23.39	24.07	42%	3%
Commercial	61.20	87.12	93.53	35%	7%
Industrial	1,449	2,387	2,375	49%	1%
PEPCO					
Residential	10.35	18.65	19.77	57%	6%
Commercial	47.85	76.65	84.97	46%	10%
Industrial	1,297	2,381	2,868	59%	19%
Delmarva					
Residential	13.19	22.93	23.17	54%	1%
Potomac Edison					
Residential	10.62	18.35	17.57	53%	- 4%
State of Maryland					
Residential	13.83	21.97	22.78	45%	4%
Commercial	59.05	85.44	92.15	37%	8%
Industrial	1,425	2,386	2,454	50%	3%

Source: Typical Electric Bills, Federal Power Commission, 1972, 1975, and 1977

Definitions: Bills are based on prevailing rates on the first day of that year. Residential, 500 kWh per month; Commercial, 1,500 kWh and 12 kW per month; Industrial, 60,000 kWh and 300 kW per month affected. A decline in the relative size of the primary metals industry, for example, would probably serve to restrain energy demand growth despite overall growth of the national economy. In addition, a corporation is not necessarily committed to a fixed electricity-to-output ratio, and can alter it by adopting different and possibly improved technologies. The decision to switch techniques (and thus energy usage) is influenced by the price of electricity relative to the price of competing inputs -- the prices of labor, capital, and substitute fuels. For example, if the price of electricity rises relative to the cost of capital, firms might respond by improving building insulation. This would tend to save on electricity usage while using more capital.

Although such factors as relative prices and income affect electricity usage, a long period of adjustment is normally required before the full effect, or even most of the impact, is fully manifested. If gas prices rise relative to electricity, households will not simply abandon gas appliances. Consumers do not immediately translate higher incomes into larger houses. Businesses cannot instantly install electricity-conserving equipment in response to current price increases for electricity. These responses do come, but they are spread out over time, and in some cases extremly long periods of time are required.

It is interesting to note in Tables B-3 and B-5 that electricity price increases in the 1975-1977 period have been quite modest (in fact, less than the overall rate of inflation) and income gains considerable, yet consumption growth is considerably slower than the pre-embargo period. This result stems in part from the fact that customers were adjusting to the massive price increases of an earlier period. Moreover, even during the next several years, consumers and businesses will be in the process of completing their adjustments to price changes of the early 1970's.

FORECASTING FUTURE USAGE

THE NEXT TEN YEARS

The Electrical Energy Forecasting Unit of the Maryland Department of State Planning, is preparing forecasts for the major utility systems operating in the State of Maryland. To date, forecasts on Potomac Electric Power Company and Baltimore Gas and Electric Company have been completed. These forecasts use statistical models to estimate the various impacts of the aforementioned factors (e.g., electricity price, income, etc.) on electricity usage patterns. Future values of these factors, based both on judgment and official government projections are then inserted into the statistical model to produce projections of future electricity consumption. This method is commonly referred to as a structural econometric approach, and possesses the advantage of explicitly and quantitatively expressing the impacts of important determinants on electric energy consumption.

Since the Department of State Planning has not yet made projections on the other Maryland utility systems -- Delmarva Power and Light Company of Maryland, Potomac Edison Company, Easton Utilities Commission, and Conowingo Power Company -- the forecasts prepared by the companies themselves are presented in Table B-5 In some cases, minor adjustments to company figures were required in order to achieve consistency in the presentation. These companies used various techniques to make their forecasts. Potomac Edison and Easton Utilities relied heavily on time trending, assuming that future growth will proceed at the same rate as past assuming that future growth will proceed at the same rate as past growth. Delmarva employs a methodology that is similar in some respects with that used and advocated by the Maryland Department of State Planning. Statistical models were used to determine the impact on electricity consumption of various factors including population, employment, manufacturing and non-manufacturing earnings, weather conditions, disposable income, use of air conditioners, and electricity prices. To project peak demand, the data were weather-adjusted to historically normal conditions, and the historical relationship was ascertained between peak demand, income, and air-conditioner ownership. These estimated relationships were then used as the basis for the company's forecasts.

The following tables present past and forecasted electric energy sales and the annual peak demand for the five major bulk suppliers of electricity in the State. Energy sales are measured in megawatt hours (each megawatt hour equals 1,000 kilowatt-hours), and the peak demand figures are in megawatts. The final table compiles the State-wide totals from the five suppliers.

In addition, many Maryland households and businesses purchase their electricity from municipally owned systems and electric power cooperatives. However, these municipal systems and cooperatives purchase power wholesale from one of three major suppliers -- Delmarva, Potomac Edison, or PEPCO, and then sell the power to their own retail customers. Thus, the figures presented for these three companies include the bulk sales to municipal systems and cooperatives, which, in turn, were divided into residential and nonresidential segments according to the same proportion as was found to exist (or projected to exist) in the retail sales of the bulk supplier.

It was explained earlier that a utility's annual peak demand is the maximum amount of demand for power during the year. Although this definition applies for each of the five systems, it is not true for the State as a whole, since the individual systems annual peaks used to tabulate the State total do not occur simultaneously. For example, PEPCO's peak normally occurs in July or August while Potomac Edison's occurs in December or January. In other words, the State peak demand figure should not be interpreted as the maximum amount of demand for power in Maryland at any one time during the year. It is merely the sum of the annual peak demands of the five systems operating in the State. However, the statewide figures are still useful for making year-to-year comparisons. Also, peak demand is measured as the maximum system power sent out at any hour during the year. This system peak cannot be broken down geographically with precision, and most utilities do not even attempt to do so. Thus, the peak demand figures for PEPCO and Potomac Edison, multistate companies, are systemwide and therefore extend beyond Maryland's boundaries. Thus, the Maryland total also includes the D.C., Virginia, and Pennsylvania portions of the PEPCO and Potomac Edison load.

The forecasts presented in Table B-5 are based upon certain expectations concerning the underlying determinants of electricty consumption. The econometric forecasts reflect these expectations explicitly, and other methods embody other implicitly formulated assumptions. Table B-4 presents the projections on population, employment, and real per capita income prepared by authoritative sources. All three variables are projected to increase, but at rates somewhat less than the rapid expansion experienced during the pre-embargo

Table B-4. Projected average annual compound growth rates on population, employment, and real per capita income

Region	1975-80	1980-1985	1985-1990
A. Population			
Baltimore Area	1.19	1.22	1.28
Easton Shore	.83	1.18	1.15
Southern Maryland	1.08	2.14	1.54
Washington Suburban	1.48	1.47	1.75
Western Maryland	.40	.61	.73
State of Maryland	1.19	1.26	1.39
B. Employment			
Baltimore Area	1.68	1.60	1.39
Eastern Shore	2.02	1.30	1.38
Southern Maryland	.82	1.46	1.67
Washington Suburban	3.39	2.72	2.30
Western Maryland	1.68	1.13	1.08
State of Maryland	2.16	1.88	1.65
C. Real Per Capita Income			
State of Maryland	3.25	2.60	2.60

Sources: Maryland Projection Series Population and Employment 1975-1990, Maryland Department of State Planning, 1977; 1972 OBERS Projections of Regional Economic Activity in the U.S., U.S. Water Resources Council, 1972

Table B-5a. Baltimore Gas and Electric*

Year	Energy (MWh)			Peak Demand (MW)
	Residential	Non-Residential	Total	
1966	2,347,000	6,306,000	8,653,000	1,817
1969	3,285,000	7,880,000	11,165,000	2,306
1972	4,102,000	8,889,000	12,991,000	2,960
1975	4,664,000	9,194,000	13,858,000	3,256
1977	5,231,000	10,231,000	15,462,000	3,588
1980	5,553,000	12,003,000	17,556,000	3,510
1985	7,175,000	15,886,000	23,061,000	4,418
1987	8,009,000	17,611,000	25,620,000	4,833
	Average Annual Compound Growth Rates			
1966-72	9.75%	5.89%	7.01%	8.47%
1972-75	4.37%	1.13%	2.18%	3.23%
1975-77	5.90%	5.49%	5.63%	4.97%
1977-80	1.99%	5.47%	4.32%	- .73%
1980-85	5.26%	5.77%	5.61%	4.71%
1977-87	4.35%	5.58%	5.18%	3.02%

*Forecasts are Maryland Department of State Planning figures

Table B-5b. Conowingo Power Company*

Year	Energy (MWh)			Peak Demand (MW)
	Residential	Non-Residential	Total	
1966	77,148	140,967	218,115	42
1969	107,195	175,886	283,081	56
1972	148,949	177,225	326,174	67
1975	193,741	185,488	379,229	78
1977	201,467	218,459	419,926	85
1980	242,000	240,686	482,686	94
1985	328,300	290,236	618,536	117
1987	366,200	313,956	680,156	128
	Average Annual Compound Growth Rates			
1966-72	11.59%	3.89%	6.94%	8.09%
1972-75	9.16%	1.53%	5.15%	5.20%
1975-77	1.97%	8.52%	5.23%	4.39%
1977-80	6.30%	3.28%	4.75%	3.41%
1980-85	6.29%	3.81%	5.08%	4.47%
1977-87	6.16%	3.69%	4.94%	4.18%

* Forecasts are company figures

Table B-5c. Easton utilities*

Year	Energy (MWh)			Peak Demand (MW)
	Residential	Non-Residential	Total	
1966	10,074	29,586	39,660	10
1969	15,456	39,999	55,455	13.5
1972	22,554	49,129	71,683	17.1
1975	26,925	59,080	86,005	20.4
1977	31,370	66,333	97,703	22.3
1980	42,189	89,211	131,400	30.9
1985	61,878	130,842	192,720	46.1
1987	72,847	154,037	226,884	54.2
	Average Annual Compound Growth Rates			
1966-72	14.38%	8.82%	10.37%	9.35%
1972-75	6.08%	6.34%	6.26%	6.06%
1975-77	7.94%	5.96%	6.58%	4.55%
1977-80	10.38%	10.38%	10.33%	11.49%
1980-85	7.96%	7.96%	7.96%	8.33%
1977-87	8.79%	8.79%	8.79%	9.29%

* Forecasts are Easton Utility Commission figures. Easton does not provide a residential/non-residential breakdown for its projected energy sales. These figures were obtained by multiplying the projected total by the 1977 actual proportions.

Table B-5d. Delmarva of Maryland*

Year	Energy (MWh) Residential	Non-Residential	Total	Peak Demand (MW)
1966	263,935	397,602	661,537	141
1969	384,606	546,410	931,016	197
1972	527,652	692,019	1,219,671	278
1975	651,955	800,041	1,451,996	342
1977	793,521	933,030	1,726,551	400
1980	951,828	1,169,854	2,121,682	435
1985	1,291,274	1,579,392	2,870,666	575
1987	1,436,701	1,788,815	3,225,516	635
	Average Annual Compound Growth Rates			
1966-72	12.24%	9.68%	10.73%	11.98%
1972-75	7.31%	4.95%	5.98%	7.15%
1975-77	10.32%	7.99%	9.05%	8.15%
1977-80	6.25%	7.83%	7.11%	2.84%
1980-85	6.29%	6.19%	6.23%	5.74%
1977-87	6.12%	6.73%	6.45%	4.73%

* Forecasts are company figures

Table B-5e. Potomac Edison, Maryland Portion*

Year	Energy (MWh)			Peak Demand (MW)
	Residential	Non-Residential	Total	
1966	495,259	944,149	1,439,408	512
1969	681,153	1,251,144	1,932,297	673
1972	902,604	2,784,419	3,687,023	1,099
1975	1,131,080	2,792,257	3,923,337	1,359
1977*	1,291,892	4,312,187	5,604,079	1,486
1980	1,640,703	5,562,721	7,203,424	1,925
1985	2,411,833	7,231,537	9,643,370	2,630
1987	2,749,490	8,027,006	10,776,496	2,995
	Average Annual Compound Growth Rates			
1966-72	10.52%	19.75%	16.97%	13.58%
1972-75	7.81%	.09%	2.09%	7.33%
1975-77**	6.87%	24.27%	19.52%	4.57%
1977-80	8.29%	8.86%	8.73%	9.01%
1980-85	8.01%	5.39%	6.01%	6.44%
1977-87	7.85%	6.41%	6.76%	7.26%

* Forecasts are company figures. The company forecasts on a systemwide (multistate) basis only. To obtain the Maryland megawatt hour projections the systemwide forecasted growth rates are applied to actual 1977 Maryland consumption.

** In 1976 Potomac Edison initiated service to the Eastalco aluminum plant.

Table B-5f. Potomac Electric Power Company (Maryland Portion)

Year	Energy (MWh) * Residential	Non-Residential	Total	Peak Demand (MW)
1966	1,488,701	2,371,608	3,860,309	2,123
1969	2,111,689	3,577,122	5,688,811	2,759
1972	2,589,262	4,491,480	7,080,742	3,479
1975	2,929,826	4,827,844	7,757,670	3,623
1977	3,168,272	5,173,975	8,342,247	3,857
1980	3,599,900	5,792,300	9,352,200	4,191
1985	4,357,700	6,423,600	10,781,300	4,393
1987	4,758,600	6,599,900	11,358,500	4,453
		Average Annual Compound Growth Rates		
1966-72	9.66%	11.23%	10.64%	8.58%
1972-75	4.21%	2.44%	3.09%	1.36%
1975-77	3.99%	3.52%	3.70%	3.18%
1977-80	3.96%	3.83%	3.88%	2.80%
1980-85	4.13%	2.09%	3.90%	.95%
1977-87	4.15%	2.46%	3.13%	1.45%

* Includes sales to SMECO. For future years projected sales to SMECO are broken down as residential and non-residential according to 1972 actual SMECO proportions.

Table B-5g. The State of Maryland

Year	Energy (MWh)			Peak* Demand (MW)
	Residential	Non-Residential	Total	
1966	4,682,117	10,189,912	14,872,029	4,645
1969	6,585,099	13,470,561	20,055,660	6,005
1972	8,293,021	17,083,272	25,376,293	7,900
1975	9,597,527	17,858,710	27,456,237	8,678
1977	10,717,522	20,934,984	31,652,506	9,438
1980	11,989,620	24,857,772	36,847,392	10,186
1985	15,625,985	31,541,607	47,167,592	12,179
1987	17,392,838	34,494,714	51,887,552	13,098
		Average Annual Compound Growth Rates		
1966-72	10.00%	8.99%	9.31%	9.25%
1972-75	4.99%	1.43%	2.66%	3.18%
1975-77	5.67%	8.27%	7.37%	4.29%
1977-80	3.81%	5.89%	5.20%	2.57%
1980-85	5.44%	4.88%	5.06%	3.64%
1977-87	4.96%	5.12%	5.07%	3.33%

* Peak demand digures include West Virginia, Virginia, D.C., and Pennsylvania loads in the PEPCO and Potomac Edison service territories.

decade. Inasmuch as there are no official projections on the future course of electricity price in the State of Maryland, it is assumed that future prices will probably rise at least modestly above the rate of inflation.* These factors, along with the delayed adjustments to 1972-1975 price increases, should serve to restrain demand below the pre-embargo growth rates.

Several factors are working the other way to increase future consumption. Although the population growth rate is expected to be lower in the future than in the past, the expected increase in the household formation rate will mean that the number of electricity customers is expected to grow considerably faster than population. Furthermore, natural gas, a major substitute for electricity, is expected to rise in price even faster than electricity, encouraging a corresponding fuel substitution. In addition, the supply restrictions on new gas hook-ups mandated in the early 1970's in Marland, are expected to continue over portions of the next ten years.

These observations apply to future growth of both energy consumption and peak demand. Peak demand is also expected to grow at a slower rate than in the pre-embargo past. As Table B-5 illustrates for most utilities and the State, it is expected to rise at a slightly lower rate than annual energy consumption. In the past, an important factor in the growth of peak demand has been the increasing utilization of air-conditioning in the residential and commercial sectors. However, in many areas of the State, particularly the wealthier suburban counties, the market for air-conditioners is reaching saturation. Thus, the impact of airconditioning on peak demand growth will be somewhat weaker than in the past. Additionally, for most Maryland utilities,** peak demand occurs during the summer months. Over the forecast period, electric space heating is expected to be installed in a large percentage of new homes -- far larger than in the past -- a trend based at least in part upon the price and availability problem associated with natural gas. This, of course, boosts the growth rate of electricity consumption, but will have little effect on peak demand in the summer peaking utility systems.

Considering the current lead times required for constructing new additions to generating capacity, electricity consumption and peak demand must be projected at least ten to fifteen years into the future. However, the state-of-the-art limits the forecaster's ability to produce reliable long-range projections. Since future demand depends on what happens to those factors that affect usage (i.e., energy prices, income, population, employment, etc.) predictions on future electricity usage can be no more reliable than the long-range projections of those factors. An accurate forecast of electric power usage in Marylad in 1987 requires precise information regarding the Maryland economy and energy prices over the next ten years.

Moreover, some of these determinants of electricity demand are subject to policy changes at both the national and state levels. Examples of public policies which will affect these factors include federal initiative to deregulate

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* See the discussion in Chapter 5 on electricity price in the forthcoming Projected Electric Power Demands for the Baltimore Gas and Electric Company, Maryland Department of State Planning, 1978.

** Potomac Edison is the only large winter peaking utility in the State.

interstate natural gas transactions, and the introduction of new building codes to alter insulation standards. Additionally, there is currently great interest in the reform of electric utility rates. Proposed changes would alter rate structures so as to price electricity according to season or time of day. The purpose of this proposed reform is to reduce the growth of peak demand. The difficulty of anticipating these kinds of policy actions introduces substantial uncertainty into the forecasts, even when the importance of such policies is fully appreciated.

It is within this environment of considerable uncertainty that demand forcasts must be formulated. It is no longer reasonable to assume that future demand growth will procede at the same rate as in the past. The Maryland Department of State Planning has produced forecasts of electric energy consumption and peak demand for two utility systems -- PEPCO and BG&E -- which specifically account for the impacts of the various major causal factors. Future efforts along similar methodological lines will result in the Department of State Planning's production of forecasts for Maryland's other two large electric utilities -- Delmarva Power and Light and Potomac Edison. Updates will also be periodically performed in order to incorporate the best and latest information available into the forecasts. Eventually, then, electricity usage in virtually the entire State of Maryland will be forecasted using structural econometric models.

<u>REFERENCES -- APPENDIX B</u>

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